87-178

Supreme Court, U.S.
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No.

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation
Petitioner,

v.

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA,
Respondent.

PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

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QUESTION PRESENTED

Does a state public utilities commission violate the Public Utility Regulatory Policies Act of 1978 and the Federal rules promulgated thereunder by requiring an electric utility to pay prices for electricity which exceed those prices authorized by the Act?

THE PARTIES TO THIS PROCEEDING

The parties to this proceeding are: (1) Pacific Gas and Electric Company* (hereinafter "PGandE") (Petitioner); (2) Public Utilities Commission of the State of California (hereinafter "CPUC" or "Commission") (Respondent); (3) Independent Energy Producers Association, Inc.; (4) Basic American Foods, Inc.; (5) GWF Power Systems Company; (6) California Agricultural Power Company; and (7) Ultrapower, Inc. (the real parties in interest).

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* PGandE is not owned by any parent company. The following is a list of PGandE's subsidiaries and affiliates and the percentage of each that PGandE owns: Pacific Indonesia LNG Company (50%); Standard Pacific Gas Line Incorporated (85.71%). PGandE has an indirect interest in Alberta Natural Gas Company Ltd, ANGUS Chemical Company, ANGUS Fine Chemicals Ltd., ANGUS Chemie GmbH., Ltd., and Rocky Mountain Gas Transmission Company through its wholly-owned subsidiary, Pacific Gas Transmission Company. Pacific Gas Transmission Company owns 49.23% of Alberta Natural Gas Company Ltd, 100% of ANGUS Petroleum Corporation, and 100% of Rocky Mountain Gas Transmission Company. Alberta Natural Gas Company Ltd owns 98.04% of ANGUS Chemical Company, and 49% of Foothills Pipe Lines (South B.C.) Ltd. ANGUS Chemical Company owns 85% of ANGUS Biotech, Inc., 100% of ANGUS Chemie GmbH., and 80% of ANGUS Fine Chemicals Ltd.

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PUBLIC UTILITIES COMMISSION OF THE
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Respondent.

PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

Pacific Gas and Electric Company ("PGandE") respectfully petitions for a writ of certiorari to review the judgment of the California Supreme Court entered on April 29, 1987, which denied without opinion PGandE's petition for writ of review from three related decisions of the California Public Utilities Commission ("CPUC" or "Commission").

OPINIONS BELOW

The judgment of the California Supreme Court is not reported, but is reprinted in Petitioner's Appendix ("Pet. App.") at p. 1. The three unreported decisions of Respondent CPUC are Decision No. 86-10-038 issued October 16, 1986 (Pet. App., p. A-126); as modified by Decision No. 86-12-013 issued December 3, 1986 (Pet. App., p. A-141); and as further modified by Decision No. 86-12-104 issued December 22, 1986 (Pet. App., p. A-145).

JURISDICTION

Respondent California Public Utilities Commission issued its first decision on October 16, 1986, modified the decision on December 3, 1986, and denied rehearing, but further modified the decision, on December 22, 1986. The California Supreme Court denied petitioner's timely petition for writ of review on April 29, 1987. The jurisdiction of this Court is invoked under Title 28, United States Code, section 1257, subdivision (3).

This Petition is being docketed in this Court within 90 days from the denial below of the writ of review.

FEDERAL STATUTE INVOLVED

This case involves Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Title 16, United States Code, section 824a-3, subdivision (3). The text of Section 210 is set forth at (Pet. App., p. A-257.)

STATEMENT OF THE CASE

A. Introduction

This case arises from three related decisions of the Commission which ordered PGandE to amend more than 200 executed power purchase agreements to add new prices in excess of PURPA's maximum rate for the purchase of future power that PGandE does not need. The additional cost, which may well exceed $1 billion, will be borne by PGandE's ratepayers.

PURPA requires electric utilities to purchase electric power produced by cogeneration and small power production "qualifying facilities" ("QF"). Under Section 210(b) of PURPA, the purchase price may equal, but cannot exceed, the utility's cost of generating the power itself or purchasing it elsewhere. This cost is called the "incremental" or "avoided" cost. If properly determined, prices based on "avoided cost" assure that utility customers' rates will remain the same regardless whether the utility buys QF power or generates the power itself. When prices are allowed to exceed avoided cost, ratepayers are forced to subsidize QF developers, which is contrary to Section 210(b) of PURPA.

Section 210(f) of PURPA requires each state authority, which in California is the CPUC, to implement the rules promulgated by the Federal Energy Regulatory Commission ("FERC") pursuant to Section 210(a) of PURPA. (18 C.F.R. Part 292 (1987).) The CPUC has chosen to do so primarily through the creation of "standard offers" for power purchase agreements that a utility must make available to all QF developers. The CPUC ordered petitioner to amend more than 200 of these executed standard offer power purchase agreements to pay prices that substantially exceed current "avoided cost" projections.

The affected power purchase agreements are with cogeneration and small power production facilities that are QFs under the regulations of FERC which implement PURPA. Even though Section 210(b) of PURPA mandates that ratepayers not pay more for QF power than the cost of the utility's alternative resources, the Commission's orders nevertheless compel PGandE to pay new, fixed prices that exceed current projections of the cost of alternate resources to QFs who will not even begin operation until after 1987. Consequently, these new prices subsidize QFs at the expense of PGandE ratepayers. Moreover, the prices not only exceed the Commission's authority under PURPA but they flaunt the express terms of the power purchase agreements.

B. Section 210 Of PURPA

Enacted in 1978, PURPA was part of the President's initiative to combat the energy crisis. (*See American Paper Institute, Inc.* v. *American Electric Power Service Corp.*, 461 U.S. 402 (1983); *FERC* v. *Mississippi*, 456 U.S. 742, *reh'g denied*, 458 U.S. 1131 (1982).) Section 210 of PURPA encouraged the development of qualifying small power and cogeneration facilities by requiring electric utilities to purchase their electric output. To implement this policy, Section 210(a) of PURPA requires FERC to promulgate regulations whereby electric utilities must offer to purchase the power generated by qualifying facilities.

Section 210(b) of PURPA delineates the rates that a utility under Section 210(a) can be ordered to pay for qualifying facilities power. These rates, according to Section 210(b), "shall be just and reasonable to the electric consumers of the electric

utility and in the public interest" and "shall not discriminate against" qualifying facilities. The maximum rate that can be set under Section 210(b) is the "incremental cost to the utility of alternative electric energy" which is known as the "avoided cost." (*See also American Paper Institute Inc.* v. *American Electric Institute, supra*, 461 U.S. at 413; 18 C.F.R. § 292.304(a)(1987).)

Section 210(f) of PURPA requires state utility regulatory commissions, such as the CPUC, to implement FERC's rules issued pursuant to Section 210(a). State commissions "may comply with this requirement by issuing regulations, by resolving disputes on a case-by-case basis, or by taking any other action reasonably designed to give effect to FERC's rules." (*FERC* v. *Mississippi, supra*, 456 U.S. at 751.)

On February 19, 1980, FERC issued its rules pursuant to Section 210(a) of PURPA. (45 Fed. Reg. 12214, *codified at* 18 C.F.R. Part 292 (1987).) Those rules require electric utilities to offer to purchase electric energy from qualifying cogeneration and small power production facilities at a rate equal to the purchasing utility's full avoided cost. (18 C.F.R. § 292.304(b)(2)(1987).) This Court has upheld the validity of FERC's full-avoided-cost rule, but it emphasized that "PURPA sets full avoided cost as the maximum rate that [FERC] may prescribe." (*American Paper Institute, Inc. v. American Electric Power Service Corp., supra*, 461 U.S. at 413.)

C. The CPUC's Implementation Of FERC's Section 210(a) Rules And Approval Of Interim Standard Offer No. 4

On September 3, 1980, the CPUC issued Order Instituting Rulemaking (OIR) 2 for the purpose of complying with PURPA's requirement that each state regulatory authority begin to implement the FERC rules within one year of their issuance. (16 U.S.C. § 824a-3(f)(1); Dec. No. 82-01-103, 8 Cal. P.U.C. 2d 20 (1982).) The CPUC chose to implement the FERC rules by creating a series of "standard offers" for power purchase agreements which the utility is required to make available to all QFs. Under these standard offers, a utility cannot refuse any QF, alter any standard offer term except at a QF's specific request, or even limit the number of standard offers which are signed. In

other words, a utility can do no more than ensure that a QF has filled in the blanks and signed the offer. (Dec. No. 85-06-163, slip op. at 24-25, 29 (Cal P.U.C., June 21, 1985).)

In 1983, the Commission approved negotiated Interim Standard Offer No. 4 ("interim SO4"), which offered long-term fixed energy and capacity prices on an interim, experimental basis. (Pet. App., p. A-186.) Interim SO4 differed from its predecessor standard offers in two important aspects. First, it allowed QFs to lock into fixed, forecasted avoided cost prices rather than rely on the fluctuating, actual avoided cost prices for both energy and capacity.[1] Second, interim SO4 was developed through negotiations between interested parties facilitated by the Commission's staff; and no evidentiary proceedings of any kind were ever conducted.[2] The negotiated interim SO4 had a menu of pricing options from which QFs could choose. Three of them are pertinent.

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[1] Electrical power is viewed as having two components, capacity and energy. "Capacity" refers to the capability of a generating facility to produce a specified amount of electrical energy at an instant in time. Capacity is measured in multiples of watts (kilowatts ("kw") or megawatts ("mw")). It is analogous to the horsepower of an engine. A one megawatt facility is capable of supplying the electrical needs of about 1,000 households. "Energy" is the electricity actually delivered to customers. It is measured in terms of volume (watts) and time (hours) and is often expressed in kilowatt-hours ("kwh"). Energy payments are generally based on the variable costs of generating the energy, primarily fuel costs, while capacity payments are generally based on the fixed costs of the capacity, such as construction costs.

[2] The CPUC had earlier approved three standard offers. Standard Offer No. 1 ("SO1") was for the purchase of "as-delivered" capacity and energy based on fluctuating, actual avoided cost prices. Standard Offer No. 2 ("SO2") was for the purchase of "firm" capacity from QFs capable of operating reliably during the utility's peak demand periods. SO2 offered fixed, levelized capacity prices, and the same actual avoided cost energy prices offered under SO1. Standard Offer No. 3 ("SO3") was for the purchase of as-delivered capacity and energy, both at actual avoided cost prices, from small QFs of 100 kilowatts or less. (*See* Dec. No. 82-01-103, 8 Cal. P.U.C. 2d 20 (1982); Dec. No. 82-12-120, 10 Cal. P.U.C. 2d 20 (1982).)

First, Energy Payment Option 1 allowed QFs to be paid for energy for up to ten years based upon the fixed prices set forth in Table B-1. (Pet. App., p. A-210.) Table B-1 contained fixed annual prices for energy deliveries in years 1983 through 1997. Thus, a QF could begin to operate as late as 1987, four years after interim SO4 was approved, and still receive ten full years of guaranteed prices.

Second, interim SO4 allowed QFs capable of operating reliably during PGandE's periods of greatest electricity demand to be paid fixed prices for "firm" capacity. These were constant, levelized prices to be paid for the term of the agreement which, at the QF's option, could range from 15 to 30 years. The exact price depended on both the term of agreement and the date on which the QF demonstrated its ability to provide reliable capacity. This date was called the "firm capacity availability date." Table E-2 provided annual prices for firm capacity availability dates for years 1982 through 1987 only. (Pet. App., p. A-238.)

Third, QFs unable or unwilling to commit to firm capacity had the option to be paid fixed prices for their "as-delivered" capacity. Table D-2 contained fixed annual prices for years 1983 through 1997. (Pet. App., p. A-230.)

On the basis of the utilities' amended applications, which presented each utility's negotiated version of interim SO4, the Commission approved interim SO4 in Decision No. 83-09-054 issued on September 7, 1983. In that decision the Commission clearly stated:

> The most critical aspect of this process is that *each agreed upon standard offer resulting from the negotiating conference is presented to us on a take-it-or-leave-it basis.* Each was truly negotiated as a "package," comprised of cost forecasts, prices, and contract terms, etc. *We are, at this juncture, without an evidentiary record* upon which to weigh various proposals and adopt a standard offer reflecting a careful weighing of various components. *Essentially, then, we face either accepting or rejecting each of the three standard offer payment options as negotiated, and we do not, in*

> *fairness to the parties, have the latitude to make modifications.* (Pet. App., p. A-9.) (Emphasis added.)

The Commission also made clear that:

> Those who contract under interim Standard Offer #4 will *not be subject to having terms or prices changed later*, except as narrowly and specifically ordered by this decision. *Any changes made to this standard offer in the future will only apply to those contracting after such changes.* (Pet. App., p. A-4.) (Emphasis added.)

Although it could have done so, the Commission nevertheless refused to approve a continuing regulatory authority clause. Instead, it specifically recognized that it would have no authority to "order retroactive changes" to signed interim SO4 power purchase agreements. (Pet. App., p. A-32.) The Commission then approved without change the three price provisions described above. It did not, however, adopt any specific standard or methodology for determining either energy or capacity prices; rather, it simply approved the specific sets of numbers contained in PGandE's application. (Pet. App., pp. A-20-A-22.) The Commission specifically stated in Finding of Fact 2:

> The amended applications in these proceedings, with the changes noted on the record during the second prehearing conference, contain Standard Offer #4. That standard offer, and three payment options under it, are acceptable to the respective utilities, QFs, and staff, for interim use. (Pet. App., p. A-44.)

The CPUC's sole Conclusion of Law states:

> *The standard offers filed by the applicant utilities should be ratified for use* by utilities and QFs in contractual power purchases, as authorized and restricted by the following order. (*Id.*) (Emphasis added.)

Finally, Ordering Paragraph 1 provides:

> 1. *Standard Offer #4, Payment Options #1 through #3, as proposed by the Pacific Gas and Electric Company*

> (PGandE), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison), *shall be used by those utilities until further order of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order. (Id.) (Emphasis added.)*

Decision No. 83-09-054 limited the availability of interim SO4 to a maximum of two years. It further limited use of two payment options—Energy Payment Options 2 and 3—to a maximum one-year period "due to reservations about whether longer provision for these options would be in the public interest." (Dec. No. 85-04-075, slip op. at 5 (Pet. App., p. A-65).) The Commission ultimately made interim SO4 available for a longer period than it had originally anticipated. But the Commission never revised either the fixed prices or the fifteen-year forecast adopted in Decision No. 83-09-054.

D. Because Of The Overwhelming QF Response To Interim SO4 And The Decline In Oil And Gas Prices, The Commission Suspended Interim SO4 In April 1985

Although asked to do so, the Commission twice specifically refused to alter the price provisions of interim SO4 in any way whatsoever. In Decision No. 83-12-050, slip op. at 4 (Pet. App., p. A-53), issued two days before PGandE's 1984 Test Year General Rate Case decision, the Commission observed:

> Standard Offer No. 4, along with the energy price, incremental energy rate and shortage value forecasts adopted by D. 83-09-054 has become effective. *New incremental energy rates and/or avoided capacity cost values that may be adopted by the Commission in general rate case or ECAC proceedings will not affect the price forecasts* established over the fixed payment term *under Standard Offer No. 4, until further orders are issued* in this proceeding. (Emphasis added.)

Moreover, continued the Commission:

> We trust there will be no further petitions for modification of that decision, as *parties should raise any concerns or propos-*

> *als relating to Standard Offer No. 4 at the upcoming evidentiary hearing.* (*Id.*) (Emphasis added.)

In Decision No. 84-08-035 issued August 1, 1984 (Pet. App., p. A-56), the Commission extended the availability of Energy Payment Options 2 and 3, which were otherwise due shortly to expire. Independent Energy Producers Association, Inc. ("IEP"), a QF trade organization, requested that Energy Payment Option 3 be modified based on information developed in the utilities' most recent general rate cases. But the Commission denied that request:

> We will not, however, amend Payment Option No. 3 in any way. That payment option was part of the negotiated package which the Commission approved in D. 83-09-054. *A change in one term would require the reexamination of all other terms of the standard offer.* We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the evidentiary hearings now scheduled in this proceeding. We also note that a QF who finds the terms of interim Standard Offer No. 4 unacceptable may in fact negotiate a separate contract. (Pet. App., pp. A-58-59.)

The extended availability of Energy Payment Option 3, however, proved short-lived. Only three months later, in Decision No. 84-10-098 issued October 17, 1984, the Commission suspended the availability of Energy Payment Option 3 for QFs over 50 megawatts. The *ex parte* suspension was prompted by the Commission's concern that over 1,800 megawatts of interim SO4s had already been signed, while large numbers of new projects loomed.

The suspension decision unleashed what became known as the "gold rush". (*See, e.g.*, Dec. No. 85-04-075, slip op. at 18 (Pet. App., p. A-83).) Because of the uncertainty over the continued availability of the interim SO4 high fixed prices, unprecedented numbers of QFs began to sign interim SO4 agreements. By December 31, 1984, QFs totaling 6,593 megawatts had executed standard offers with PGandE, primarily interim SO4. (Dec. No. 85-04-075, slip op. at A-19 (Pet. App., p. A-117).) Yet, PGandE's resource plan showed a need for only 2,829 megawatts

of QF capacity through year 2004. (*Id.* at A-21 (Pet. App., p. A-119).)

Finally, on April 17, 1985 in Decision No. 85-04-075, the Commission temporarily suspended interim SO4 in its entirety for all QFs. (Pet. App., p. A-61.) The Commission noted that the rapid rate at which QFs had signed interim SO4 with PGandE indicated that "the overall pricing terms, including both capacity and energy provisions, may be seen as very favorable by QFs." (*Id.*, slip op. at 16 (Pet. App., p. A-81).) The Commission concluded in Finding of Fact 22 that:

> Under the present terms of interim SO4, there is a reasonable probability that the utilities and their ratepayers are paying too great a price for QF electricity. (Pet. App., p. A-102.)

The Commission's analysis did not include any interim SO4s executed after December 31, 1984. (Pet. App., p. A-89.) In fact, more than 2000 megawatts of additional interim SO4s were signed after that date. On July 10, 1985, the Commission made the interim SO4 suspension permanent.[3] (Dec. No. 85-07-021).

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[3] The California Energy Commission recently summarized the situation that now faces California utilities, including especially PGandE:

> [T]he state's major utilities face substantial additional capacity surpluses for the next decade. Nor can the utilities continually absorb energy production from additional power plants; instead, there is an increasing tendency of new must-run QFs to displace energy generation from utility resources that are either less expensive to operate or never intended to be curtailed to any significant extent, or both. (1986 Electricity Report, p. 5-52.)

The California Energy Commission ("CEC") adopted this report on December 17, 1986, and modified it on January 20, 1987. As mandated by California Public Resources Code § 25308, the report presents the CEC's adopted electrical forecast for use in planning and approval of new electrical resource additions in California. PGandE asked the California Supreme Court to take judicial notice of the findings of this report pursuant to California Evidence Code §§ 452, 459.

E. Proceedings Below

In August 1986, several QFs, who had signed interim SO4 shortly before its suspension, petitioned the Commission to modify its original 1983 decision approving interim SO4. They asked the Commission to order PGandE to add new fixed energy and capacity prices to their interim SO4's so that they could begin operations after 1987 and still retain a full set of high fixed prices. In other words, they wanted these new fixed prices calculated not from current estimates of avoided cost, but from escalation of the original price schedules, which are two to four times higher than current projections of avoided cost.

The Commission held no evidentiary proceedings to consider the petitions. Instead, based on the QFs' petitions and the responses of interested parties, including PGandE, the Commission, on October 16, 1986, issued Decision No. 86-10-038. (Pet. App., p. A-126).) That decision ordered PGandE to amend all its interim SO4 power purchase agreements to add new, additional fixed prices for firm capacity based on escalation of the original fixed price schedule. The new firm capacity prices, however, were made available only to QFs who had predicted operation dates after 1987 in their interim SO4's. It also refused to alter the energy or as-delivered capacity prices.

The Commission made no attempt to determine whether the new prices in fact represented PGandE's avoided cost. To the contrary, the Commission had already previously concluded there was a "reasonable probability" that such prices would exceed avoided cost. (Dec. No. 85-04-075, slip op. at 31 (Pet. App., p. A-102); *Accord* Dec. No. 87-01-049, slip op. at 8 (Pet.App., p. A-254.).) Concerned about this huge overpayment to QFs, PGandE requested a rehearing based in part on the argument that the Commission's order violated both PURPA and the FERC rules.

The hundreds of gold rush interim SO4s signed in the last days of that offer's availability aggravated, if not caused, the situation the CEC described. The same gold rush interim SO4s are the least likely to begin operation by the end of 1987. Thus, the gold rush interim SO4s are the most likely to benefit from the new fixed prices.

On December 2, 1986, while PGandE's application for rehearing was pending, the Commission on its own motion, again without hearing, modified its prior decision to give the new, escalated firm capacity prices to all QFs with interim SO4, irrespective of their scheduled operation date. (Dec. No. 86-12-013 (Pet. App., p. A-141).)

Finally, on December 22, 1986, the Commission issued Decision No. 86-12-104, denying PGandE's petition for rehearing of the new firm capacity prices. (Pet. App., p. A-145.) The Commission reversed its earlier refusal to change the prices for energy and as-delivered capacity. Instead, it ordered PGandE to add new fixed energy and as-delivered capacity prices as well.

A timely petition for writ of review was filed with the California Supreme Court, which denied the petition without opinion on April 29, 1987. (Pet. App., p. A-1.)

THE FEDERAL QUESTION WAS RAISED BELOW

At the earliest possible stage of this proceeding, petitioner raised the federal issue. (Pet. App., p. A-168.) Among the grounds for the petition for a writ of review to the California Supreme Court was that Decision No. 86-10-038, as modified by Decision No. 86-12-013, and Decision No. 86-12-104, was unlawful because: "federal law prohibits the Commission from ordering PGandE to purchase power from qualifying facilities at prices in excess of avoided cost. (U.S. Const. art. VI, clause 2 (Supremacy Clause); Section 210(b) of PURPA, 16 U.S.C.A. § 824a-3(b); 18 C.F.R. § 292.304(d)(1986).)"

REASONS WHY THE QUESTION PRESENTED IS SUBSTANTIAL AND THE WRIT SHOULD THEREFORE BE GRANTED

I

AN IMPORTANT FEDERAL ISSUE THAT IS NATIONAL IN SCOPE IS RAISED BY THE DECISION BELOW

A. The Decision Below Raises A Recurring Federal Issue Concerning The Implementation Of PURPA

1. Introduction

The decision below raises the important national question whether in implementing PURPA a state regulatory commission can order an electric utility to pay the developers of qualifying facilities prices that exceed avoided cost forecasts, despite the clear language of Section 210(b) of PURPA which establishes avoided cost as the maximum rate a utility can be compelled to pay in implementing PURPA. For three reasons the question raises an important national issue which should be resolved by this Court.

2. Because PURPA Is A Key Part Of National Energy Policy, It Must Be Implemented Correctly

Not only is PURPA a key part of national energy policy, it is also a catalyst in making the electric utility business an increasingly competitive industry. As FERC recently noted:

> Wholesale electricity markets are becoming more competitive due to economic and technological changes. . . .
>
> Utilities are now vying against each other for sales to other utilities and to large customers. Independent generators are entering bulk power markets at both large and small scales. Distributors and large industrial customers are actively searching for new lower cost suppliers. *Pacific Gas and Electric Company*, 38 FERC ¶ 61,242 (1987).

PURPA was designed to foster competition within the industry by eliminating perceived institutional barriers to the development of non-utility, decentralized power production. It was never in-

tended to subsidize the development of cogeneration and small power producers. Interpreting PURPA as authorizing prices that exceed avoided cost not only subsidizes independent power producers contrary to congressional intent, but it also creates severe distortions in the increasingly competitive bulk and retail power markets that could adversely affect the utility industry for many decades.

3. Improper Implementation Of PURPA Will Cause Utility Customers To Pay Excessive Rates

Although Section 210(b) of PURPA declares that power purchase rates "shall be just and reasonable to the electric consumers of the electric utility" (16 U.S.C. § 824a-3(b)(1)), rates ordered by the CPUC which are above avoided cost will result in utility consumers paying QF developers payments that greatly exceed the actual value of the QFs' generation. This is highly unfair to utility customers who are already burdened with high bills for an essential service. For PGandE customers alone, the overpayments may well exceed $1 billion.[4]

4. Review Is Necessary To Resolve A Conflict Among Different Courts As To The Proper Interpretation Of PURPA

Review is necessary to resolve the conflict created by at least two other inconsistent state court decisions interpreting PURPA. In *Kansas City Power & Light Co. v. State Corp. Commission*, 234 Kan. 1052, 1057, 676 P.2d 764, 767-68 (1984), the Kansas Supreme Court held that the Kansas Corporation Commission had no jurisdiction to require Kansas Power and Light Company to purchase electricity from cogenerators at rates higher than avoided cost. But, in *Consolidated Edison Co. v. Public Service Commission*, 472 N.E.2d 981, 63 N.Y.2d 424 (1984), *appeal dismissed*, 470 U.S. 1075 (1985), the New York Court of Appeal

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[4] The California Energy Commission staff testified that the overpayments for one 120 megawatt facility have a net present value of $100 million. (PGandE Motion for Expedited Treatment, Ex. 1.) Almost 200 other power purchase agreements for approximately 4,000 megawatts would be amended to add the new higher prices as well.

held that PURPA did not preempt a state statute which established a purchase rate of 6¢/kWh, concededly above avoided cost, for utility purchases of QF generation. The real parties in interest asserted below that this Court's dismissal of the *Consolidated Edison* appeal leaves each state free to dictate to utilities whatever prices it wishes for utilities to pay for QF generation even if such prices exceed PURPA's avoided cost maximum. Unless this conflict is resolved, there will be national uncertainty in the implementation of PURPA.

II

COMPELLING PGandE TO PAY PRICES THAT EXCEED AVOIDED COST VIOLATES PURPA AND FERC RULES

A. The Commission Cannot Overrule PURPA's Mandate That Utilities Pay No More Than Avoided Cost For QF Power

Compelling a utility to purchase QF power at rates exceeding the utility's avoided cost violates Section 210(b) of PURPA. That Section states that the price prescribed for purchase of QF power "shall be just and reasonable to the electric consumers of the electric utility." (16 U.S.C. § 824a-3(b).) Accordingly, no rule "prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." (*Id.*) Moreover, the Conference Report on PURPA also confirms that Congress did not intend that ratepayers subsidize cogeneration and small power production. That report specifically states:

> The conferees intend that the phrase 'just and reasonable to the electric consumers of the utility' be interpreted in a manner which looks to protecting the interests of the electric consumer in receiving electric energy at equitable rates. (House Conference Report No. 95-1750, 95th Cong., 2d Sess. *reprinted in* 1978 U.S. Code Cong. & Ad. News 7797, 7831.)

With respect to Section 210(b), the Report indicates:

> This subsection further states that the utility would not be required to purchase electric energy from a qualifying

> cogeneration or small power production facility at a rate which exceeds the *lower* of the rate described above, namely a rate which is just and reasonable to consumers of the utility, in the public interest, and nondiscriminatory, or the *incremental cost of alternate electric energy*. This limitation on the rates which may be required in purchasing from a cogenerator or small power producer is meant to act as an *upper limit* on the price at which utilities can be required under this section to purchase electric energy. (*Id.* at 7832. (Emphasis added).)

Finally, the conferees specifically added that:

> The provisions of this section are *not intended to require the ratepayers of a utility to subsidize cogenerators or small power producers.* (*Id.*) (Emphasis added.)

It is thus clear that Congress intended that utility customers pay no more than avoided cost and not subsidize QF developers in their production of energy sold to electric utilities.

B. Unlike New York, California Similar to Kansas Has Not Enacted A Statute Which Independently Authorizes The CPUC To Set Prices That Exceed Avoided Cost

Here, unlike in New York, the California Legislature has not enacted a statute which independently authorizes the CPUC to set prices that exceed avoided cost. It is this point which distinguishes *Consolidated Edison* from the instant case. *Consolidated Edison* does not stand for the proposition that other states may mandate prices above avoided costs when implementing PURPA. For two reasons, the *Consolidated Edison* decision, which was appealed to this Court and dismissed, applies only in New York and not in California. First, as a general rule, "[a] summary disposition affirms only the judgment of the court below, and no more may be read into [that] action than was essential to sustain that judgment." (*Anderson v. Celebrezze*, 460 U.S. 780, 784-85 n. 5 (1983).) In other words, a summary disposition's precedential effect extends no further than "'the precise issues presented and necessarily decided by th[e] actions.'" (Id.) Second, and most importantly, the *Consolidated Edison* case addressed a New York statute which specifically authorized a price in excess of avoided

cost, thus giving independent state authority to the New York Public Service Commission to mandate a price in excess of avoided cost.

But California, like most other states, has not enacted such a statute. Instead, it adopted Public Utilities Code section 2821,[5] which authorizes the CPUC to set "equitable charges" for utility purchases of QF generation. Section 2821 therefore is no more than an enabling act that confirmed the CPUC's authority to implement the FERC rules. It closely resembles the statute that was at issue in *Kansas City Power & Light Co. v. State Corp. Commission, supra*, where the Kansas Supreme Court held the state had no authority under Kansas law to require a utility to purchase electricity at rates higher than avoided cost.

By statute, New York mandated a flat 6¢/kwh minimum purchase price. On the other hand, the Kansas statute, similar to California's statute, required utilities to enter into contracts that provided "fair and equitable compensation" for energy delivered to them. (K.S.A. § 66-1,184.) Section 2821, like the Kansas statute, merely authorizes the CPUC to set "equitable charges" for utility purchases of QF power.

Unlike the New York statute, Section 2821 does not authorize the Commission to establish prices that are above avoided cost. Instead, the California statute's history shows that "equitable charges" should be read as a state parallel to the concurrent federal PURPA requirement that electric utility purchases from

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[5] "The commission shall approve and establish equitable charges to be paid by an electrical corporation which purchases electricity or electrical generating capacity, or both, from any private energy producer employing other than a conventional power source for the generation of electricity.

The commission may also specify the prices, terms, and conditions for the purchase or sale of electricity or electrical generating capacity, or both, between an electrical corporation and a private energy producer, and these prices, terms, and conditions, so specified, shall be considered reasonable and prudent for all purposes. The commission may act to specify these prices, terms, and conditions on its own motion or on application of an electrical corporation or a private energy producer."

QFs be at rates which are "just and reasonable" and which do not "exceed the incremental cost to the electric utility of alternate electric energy." (16 U.S.C. § 824a-3(b).) Section 2821 originated in Assembly Bill ("AB") 1403. Its legislative history shows that it was intended to approve the Commission's choice of "avoided cost" as the yardstick for utility purchases of QF power. For example, the analysis of AB 1403, provided by the Assembly Finance, Insurance and Commerce Committee dated January 11, 1980 (Pet. App., p. A-263), states that two Commission decisions both issued December 19, 1979, Decision No. 91109 and Decision No. 91107, "accomplish the intent" of AB 1403. According to the analysis, these two decisions:

> . . . require that rates paid by utilities for electricity produced from a company which utilizes cogeneration technology must be at a utility's "avoided cost." "Avoided costs" reflect the costs of building new power plants to generate electricity that can be purchased elsewhere. (Pet. App., p. A-265.)

Since "avoided cost" prices "accomplish the intent" of Section 2821, it is therefore clear the CPUC has no statutory authority to set rates above avoided cost. Moreover, even the Commission recognized this by its failure to invoke Section 2821 to justify its orders for prices higher than avoided cost. Furthermore, it has never defined "equitable rates" as anything other than "avoided cost." Even the CPUC's Answer to PGandE's Petition for Writ of Review to the California Supreme Court acknowledged that the Commission "chose avoided cost as the standard to be applied in California." (CPUC Answer, pp. 4-5; *accord* Dec. No. 82-12-120, 10 Cal. P.U.C. 2d 553, 558 (1982); Dec. No. 82-01-103, 8 Cal. P.U.C. 2d 20, 40-41 (1982).) And, the Commission has never attempted to deviate from that standard, even in authorizing interim SO4. (Pet. App., p. A-4.) Thus, since the Commission has no statutory authority to mandate prices above avoided cost, its orders compelling PGandE to pay new capacity and energy prices that exceed avoided cost violate PURPA.

C. FERC Rules Not Only Require That Petitioner Be Forced To Pay No More Than Avoided Cost Prices, But Also That Such Costs Be Calculated At Either The Time Of Delivery Or At The Time The Obligation Is Incurred

FERC rules require that QF power sold under a fixed term agreement be priced at avoided cost calculated either at the time of delivery or at the time the power purchase agreement is executed:

> [T]he rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided cost calculated at the time of delivery; or
>
> (ii) The avoided cost calculated at the time the obligation is incurred. (18 C.F.R. § 292.304(d)(2) (1987).)

The new fixed capacity and energy prices that the Commission ordered added to interim SO4 power purchase agreements totally ignored this rule. Since the interim SO4 agreements, in fact, fixed prices in advance, they obviously do not represent avoided cost calculated at the time of the future deliveries. Yet, neither do they represent avoided cost calculated when the power purchase agreements were signed or ordered amended.

No participant in the proceedings below even attempted to demonstrate that the new fixed prices equal current estimates of avoided cost. To the contrary, PGandE showed that the prices greatly exceeded current forecasts of the value of additional, not yet operational resources. In not one of its three decisions below did the Commission purport to find that the new fixed prices represent avoided cost. Nor did it do so in Decision No. 83-09-054 when it originally approved interim SO4. Accordingly, the Commission's orders compelling PGandE to pay the new fixed capacity and energy prices violated PURPA and the FERC rules promulgated thereunder.

D. The New Escalated Firm Capacity Prices Did Not Represent Avoided Cost

The explicit Table E-2 prices for firm capacity deliveries beginning in years 1982 through 1987 are the only prices that the Commission approved in Decision No. 83-09-054 as an acceptable projection of avoided cost. During the 1983 negotiations, the negotiators agreed to use the firm capacity price schedule that the Commission had earlier approved for PGandE's Standard Offer No. 2 ("SO2"). (Dec. No. 83-09-054, slip op. at 55, Finding of Fact 1, 2 (Pet. App., p. A-44).) It contained prices only through 1987. PGandE took the SO2 schedule, incorporated it into proposed interim SO4, and presented the entire standard offer to the Commission for approval. The Commission approved Table E-2 without change. (*Id.*, Ordering Para. 1.) In Decision No. 86-10-038, the Commission ordered PGandE to calculate new prices for firm capacity deliveries beginning in 1988, 1989 and 1990 based on the combustion turbine costs and escalation factors "implicit" in Table E-2. For four reasons, the new prices generated from these old assumptions do not comply with FERC rules.

First, the Table E-2 prices, and not the underlying assumptions, alone represent avoided cost calculated when interim SO4 was approved and the obligation to purchase incurred. Second, the assumptions used to produce the Table E-2 prices had a limited life; they were valid only in 1983 and only then to calculate prices ending in 1987. (*See* Dec. No. 83-10-093, slip op. at 11 (Cal. P.U.C., October 10, 1983); Dec. No. 84-03-092, slip op. at 19 (Cal. P.U.C., March 21, 1984).) The assumptions were soon superseded. Only four months after the Commission approved interim SO4, it issued PGandE's 1984 Test Year Rate Case decision which adopted new assumptions and new prices for firm capacity deliveries beginning in years 1983 through 1988.[6] (*See* D. 83-12-068, Table VI-4, slip op. at 349 (December 22, 1983).)

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[6] The Commission eventually concluded that these firm capacity prices would also overvalue additional QF capacity. On March 19, 1986, the Commission accordingly suspended Standard Offer No. 2. *See* Dec. No. 86-03-069 (Cal. P.U.C., March 19, 1986); Dec. No. 86-05-024 (Cal. P.U.C., May 7, 1986).

Yet, the Commission chose not to make the new prices applicable to the negotiated interim SO4. (*Id.*) Third, as the California Energy Commission recently stated regarding the interim SO4 firm capacity payment option, the assumed gas turbine proxy used to construct the Table E-2 prices is now outmoded:

> The most prevalent option values the QF's capacity by assuming that in the absence of the QF, the utility would meet its growing capacity requirements by constructing a gas turbine power plant. This assumption may have been reasonable for utilities planning to add new capacity in the near term, but since the CPUC placed no limit on the amount of QF capacity that could accept the standard offer, the extended availability of these standard offers implied that there was no limit to the amount of capacity needed by the utilities. By the time the CPUC moved to suspend the long-run standard offers, thereby correcting this erroneous and unintended implication, far more QF capacity had signed the standard offers than the utilities could possibly need for the foreseeable future. (1986 Electricity Report, pp. 5-51, 5-52.)

Finally, even the old assumptions underlying Table E-2 are insufficient to generate the new, escalated prices the Commission ordered. The Table E-2 prices through 1987 were based on projections of capacity costs for thirty years, or through year 2017. Generating new prices for three more years—1988, 1989 and 1990—requires new assumptions for capacity values in 2018, 2019 and 2020. The value of capacity for these years is in no way implicit in Table E-2. The Commission never purported to approve forecasted capacity values for those years. Accordingly, it never determined that the new firm capacity prices represent avoided cost. Those prices therefore do not comply with PURPA or FERC rules.

E. By The Commission's Own Admission, It Never Found That The New Extended Energy Prices Represent Avoided Cost, And This Failure Violated PURPA And FERC Rules

By its own admission, the Commission never found that the new fixed energy prices represented avoided cost. For example, in Decision No. 86-10-038, slip op. at 12 (Pet. App., p. A-136), the

Commission stated there was "no accepted methodology" to extend Table B-1. It further stated in Decision No. 86-12-104 that Table B-1 was "based on negotiations between the parties, which cannot be replaced without long and complex hearings for the sole purpose of adopting a workable methodology." (Pet. App., p. A-146.)[7] And finally in Decision No. 83-09-054, slip op. at 10 (Pet. App., p. A-7), the Commission repeatedly stated it had no evidentiary record to do anything other than accept or reject that to which the negotiators had agreed.

The last price in Table B-1 is 13.14 cents per kilowatt hour ("¢ /kw") for 1997 energy deliveries. The current avoided cost forecast of the Commission's Public Staff Division is only 4.79¢ /kwh for 1998, 5.29¢/kwh for 1999 and 5.93¢/kwh for 2000. (PGandE's Protest, Ex. 3) The interim SO4 negotiators agreed to a price of 13.14¢/kwh for 1997 alone; they never agreed to pay that same price in 1998, 1999 and 2000 as well. Nonetheless, the Commission ordered PGandE to pay the last negotiated price in Table B-1 for three additional years. Extending Table B-1 for an additional three years, in the admitted absence of any determination or agreement that the last negotiated price represents avoided cost, flagrantly violates PURPA and FERC rules.

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[7] The Commission made the same statements regarding extension of the fixed as-delivered capacity prices in Table D-2. However, interim SO4 already gave QFs the right to retain the last Table D-2 price as a floor price for the rest of their term of agreement. Thus, unbeknownst to the Commission, the effect of the Commission's extension of the last price in Table D-2 was simply to reconfirm what interim SO4 had already explicitly provided.

III

THE NEW FIXED ENERGY AND CAPACITY PRICES WERE NOT MERE CONTRACT INTERPRETATIONS WHICH NEEDED NO EVIDENTIARY RECORD

A. Since There Was No Evidentiary Record, The Commission's Interpretation Of The Agreements Is Not Binding On Appeal

The Commission's findings regarding the "intent" of interim SO4 rest on no evidentiary record. As the Commission itself has acknowledged, "[s]ince the present interim SO4 is a negotiated offer, there was no evidentiary record." (Dec. No. 85-04-075, slip op. at 19 (Pet. App., p. A-84.).) The Commission even told the utilities to delay executing interim SO4 until the period for petitioning for rehearing of its decision approving interim SO4 had expired "in view of our acting without an evidentiary record upon which to make findings of fact sufficient to issue a decision to withstand judicial review." (Dec. No. 83-09-054, slip op. at 54 (Pet. App., p. A-43.).)

The Commission did not even purport to conduct any evidentiary hearings prior to issuing its 1986 decisions extending the interim SO4 price schedules. In its Answer to PGandE's Petition for Writ of Review to the California Supreme Court, the Commission points out that the QFs themselves argued that no evidentiary hearings were required. (CPUC Answer, p. 10.) PGandE similarly did not request evidentiary hearings. Thus, all parties below chose to rest upon the language of interim SO4 and the authorizing decisions. None elected to invoke the aid of any extrinsic evidence.

Since the Commission's decisions rest on its interpretation of interim SO4 and its prior decisions, not upon extrinsic evidence and a record developed through evidentiary hearings, the questions presented below were solely questions of law which the California Supreme Court should have independently determined, but refused to do so. Unless the interpretation of a written document turns upon the credibility of extrinsic evidence, the reviewing court must independently interpret its legal significance. (*First National Bank of Fayetteville v. Smith*, 508 F.2d

1371, 1374 (8th Cir. 1974), *cert. denied*, 421 U.S. 930 (1975). And, no deference is due to the Commission's interpretation of the legal significance of the written material it relied upon to justify extending the interim SO4 price schedules. (*Coca-Cola Co. v. Atchinson, Topeka and Santa Fe Railway Co.*, 608 F.2d 213, 218 (5th Cir. 1979).)

The general rule that a public utilities commission is not charged with the enforcement of private contracts has been affirmed in numerous states.[8] For example, in *Afton Energy, Inc. v. Idaho Power Co.*, 729 P.2d 400 (Idaho 1986), the Idaho Supreme Court affirmed the Idaho Public Utilities Commission's refusal to interpret a power purchase agreement between a utility and a qualifying facility entered into pursuant to PURPA. The Idaho Court stated:

> Generally, construction and enforcement of contract rights is a matter which lies in the jurisdiction of the courts and not in

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[8] *General Cable Corp. v. Citizens Util. Co.*, 27 Ariz. App. 381, 555 P.2d 350, 355 (1976) ("construction and interpretation to be given to legal rights under a contract resides solely within the courts and not with the Corporation Commission"); *Wilshire Construction Co. v. Union Electric Co.*, 463 S.W.2d 903, 905 (Mo. 1971) (meaning of contracts based on rate schedule filed with PUC matter for courts, not PUC); *Williams Electric Coop. v. Montana-Dakota Util. Co.*, 79 N.W.2d 508, 517 (N.D. 1956); *Ranft v. Columbia Gas of Ohio, Inc.*; 58 Ohio App. 2d 39, 388 N.E. 2d 759, 761 (1978) (although utility terminated service pursuant to PUC order, courts, not PUC, had power to determine legal rights and liabilities under affected contract); *Gibson v. Elmor City Tel. Co.*, 411 P.2d 551, 553 (Okl. 1966); *Lacy v. East Broad Top R.R. & Coal Co.*, 168 Pa. Super. 351, 77 A.2d 706, 710 (1951); *Amerada Petroleum Corp. v. R.R. Comm'n*, 395 S.W.2d 403, 406 (1965); *Appalachian Power Co.* v. *John Stewart Walker, Inc.*, 214 Va. 524, 201 S.E.2d 758, 764 (1974) (although PUC had power to issue order ending utilities' obligation under pre-existing oral contracts to install underground electrical service free of charge, PUC had no power to adjudicate common law contract claims which arose before the order); *Benwood-McMechen Water Co. v. City of Wheeling*, 121 W.Va. 373, 4 S.E.2d 300, 303 (1939) (PUC has authority to pass on whether utility may enter into contract, but once contract is signed, its interpretation is to be determined by the courts).

> the Public Utilities Commission. This is true notwithstanding that the parties are public utilities or that the subject matter of the contract coincides generally with the expertise of the commission. If the matter is a contractual dispute, it should be heard by the courts.

Interpretation of written documents by courts, rather than by administrative agencies, is a general principle of administrative law. In *Cincinnati Gas and Electric Co. v. Federal Energy Regulatory Commission*, 724 F.2d 550, 554 (6th Cir. 1984), the court summarized the standard of review for administrative interpretation of contracts. At issue in *Cincinnati Gas & Electric* was FERC's interpretation of a transmission "wheeling" agreement between utilities. There the court stated:

> Under general contract law, interpretation of a contract is a question of law, not fact. "Questions of law, unlike questions of fact, are freely reviewable by the court." An agency's interpretation of a contract, therefore, may be reviewed by a court without special deference. (Citations omitted).

On the other hand, it is generally true that "courts do defer to contract interpretation based upon an agency's factual findings or technical expertise." (*Id.*) But, where the administrative decision is based "on the language of the Agreement rather than any factual or technical grounds, [a] Court need not defer to the Commission's interpretation but can review it freely." (*Id.*) Since the CPUC based its decision on the language of interim SO4, and did not consider extrinsic evidence or invoke any technical expertise,[9] it determined the legal significance of the agreement and the appropriate standard is *de novo* review.[10] It is well-settled that in

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[9] *See Franz v. Bd. of Medical Quality Assurance*, 31 Cal.3d 124, 140 (1982) ("due process requires, when in an adjudication an agency intends to rely on members' expertise to resolve legislative-fact issues, that it notify the parties and provide an opportunity for rebuttal").

[10] *Accord J.I. Case Co. v. NLRB*, 321 U.S. 332, 340 (1944); *Great N. Ry. v. Merchants Elevator Co.*, 259 U.S. 285, 291 (1922) (construction of tariff presents question of law absent extrinsic evidence); *Swearingen Aviation Corp. v. NLRB*, 568 F.2d 458, 463 (5th Cir. 1978) (Despite general deference to NLRB findings of fact, "[w]here, as in this case,

reviewing agency decisions of questions of law, courts "can determine such questions de novo." (*First National Bank in Sioux Falls v. National Bank of South Dakota,* 667 F.2d 708, 711 (8th Cir. 1981).)

The Commission has stated that the standard offers are to be a "contract in the 'traditional' legal sense," and interpreted accordingly. (Dec. No. 85-06-163, slip op. at 29 (Cal. P.U.C., June 21, 1985).) Therefore, an independent determination of the meaning of interim SO4 should be made because the situation presented here is the same as when an appellate court reviews a trial court's interpretation of a contract in the absence of extrinsic evidence.

B. The Clear Terms Of Interim SO4 Did Not Allow The Commission To Imply New Fixed Prices.

The Commission claimed the intent of interim SO4 was to give QFs price certainty and justified the new fixed prices accordingly. But interim SO4 contains no permanent price guarantee; its very name belies that proposition. It was intended to be available for only a limited period. It prescribed prices for only a limited period. The obvious uncertainties inherent in avoided cost forecasts, and lack of any evidentiary testing of the negotiated price package, precluded unlimited price assurance.

As a result, interim SO4 constituted a mere proposal to enter into a power purchase agreement only at the fixed prices explicitly quoted. QFs accepted interim SO4 by filling out interim SO4, signing it, and submitting it to PGandE. PGandE had no control over which of the various price options a QF opted to select. But, a QF's unilateral decision to begin operation after 1987 gave it no right to change the express prices of the offer. Thus, interim SO4 only offered price certainty to QFs who began operation in time to receive the fixed prices contained in the price schedules.

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the crucial issue is the legal significance of a written statement, neither the statute authorizing review nor respect for the Board's expertise so limit our review."); *Beryllium Corp. v. United States,* 449 F.2d 362, 366 (Ct.Cl. 1971); *New York Susquehanna & W. R.R. Co. v. Follmer,* 254 F.2d 510, 513 (3rd Cir. 1958).

C. Article 2 Of Interim SO4 Conclusively Establishes That The Price To Be Paid QFs Is Set Forth In The Price Schedules

Moreover, Article 2 of interim SO4 conclusively establishes that the only fixed prices to which QFs are entitled are those that are contained in the price schedules. Although totally ignored by the Commission in each of its three decisions, Article 2 prohibits precisely the price change that the Commission ordered. Article 2 states:

> The prices to be paid Seller for energy and/or capacity delivered pursuant to this Agreement have *wholly* or *partly* been fixed at the time of execution. Actual avoided cost at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this Agreement. Therefore, *the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance and shall not seek to or have a right to renegotiate such prices for any reason.* As part of its consideration for the benefit of fixing *part or all* of the energy and/or capacity prices under this Agreement, *Seller waives any and all rights to judicial or other relief from its obligations and/or prices* set forth in Appendices B [energy], D [as-delivered capacity], and E [firm capacity] or modification of any other term or provision for any reasons whatsoever. (Pet. App., p. A-187.) (Emphasis added.)

The clear language of Article 2 must prevail over any contrary meaning the Commission may elect to give that language. "It is clear that implication that would otherwise be reasonable should not be made when the contrary is indicated in clear and express words." (*Clutts v. Southern Methodist University*, 626 S.W.2d 334, 336 (Tex. App. 1981) quoting Corbin, 3A *Corbin on Contracts* § 564 at 298 (1960).) "Courts will not disregard the plain language of a contract or interpolate something not contained therein." (*Standard Oil Company v. Ogden & Moffett Co.*, 242 F.2d 287, 292 (6th Cir. 1957).) Article 2 prohibits any changes to the fixed prices. This alone makes untenable the Commission's implication of new fixed prices.

D. Since The Commission's Incorrect Application Of PURPA And FERC Rules Will Most Likely Cost California Ratepayers Over $1 Billion In Unnecessary Rates, It Is Critical That This Court Accept Review

This Court should grant certiorari "in view of the fiscal importance of the question." (*Alaska v. American Can Co.*, 358 U.S. 224, 225 (1959).) Here, the Commission's refusal to adhere to PURPA and FERC rules will in all likelihood cost California ratepayers more than $1 billion. In *United States v. Zazove*, 334 U.S. 602, 614-615, n. 17 (1948), this Court observed there that "if settlement were required to be made pursuant to the Circuit Court's holding would amount to approximately 1.8 billion dollars." And, in *Commissioner of Internal Revenue v. Standard Life & Accident Insurance Co.*, 433 U.S. 148, 151, n. 5, (1977), the Court again observed, in a case involving the net value of unpaid life insurance premiums: "We are informed that substantially more than $100 million is in dispute." Thus, this Court is not unmindful that erroneous decisions may have enormous financial consequences. Unless the decision below is corrected by this Court, it will in all probability cost PGandE's ratepayers $1 billion, if not more. This is egregious, especially since the record below is wholly lacking in any evidence to support this enormous gift of ratepayer funds to QFs.

Finally, it must be emphasized again that the Commission's orders compel PGandE to pay new, excessively high prices to QFs whose projects will not begin operations until after 1987 and who, for the most part, signed interim SO4 just before it was withdrawn. This is especially unjust since the Commission has never determined that the new prices represent a reasonable projection of PGandE's avoided cost. To the contrary, these new fixed prices are more than double current estimates of the future value of incremental resources in 1988 and beyond. By encouraging otherwise uneconomic projects to proceed, the decisions exacerbate the substantial generating capacity surplus that the California Energy Commission has projected for the next decade. An enormous wealth transfer from PGandE's ratepayers to the QF industry will result if the decision below is allowed to stand.

CONCLUSION

For these reasons, a Writ of Certiorari should issue to review the judgment and opinion below.

Respectfully submitted,

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Dated: July 22, 1987

Supreme Court, U.S.
FILED
JUL 28 1987
JOSEPH F. SPANIOL, JR.
CLERK

87-178

No.

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation
Petitioner,

v.

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA,
Respondent.

APPENDIX TO PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

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APPENDIX A

Order Denying Alternative Writ

S.F. No. 25114

In the Supreme Court of the State of California

In Bank

Pacific Gas and Electric, Petitioner

v.

Public Utilities Commission, Respondent.

Panelli, J., Did Not Participate

[Filed April 30, 1987]

Petition for Writ of Review DENIED.

/s/ Lucas

Chief Justice

APPENDIX B

Decision 83-09-054 September 7, 1983

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983 and August 2, 1983)

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982; July 11, 1983 and August 10, 1983)

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for an Order by the California Public Utilities Commission Directing Edison to Purchase Power from Qualifying Facilities Based on a Standard Offer for Firm Capacity and Energy Based on Long-Run Marginal Costs (OIR-2).

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983, and August 2, 1983)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power from Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.

(For appearances see Appendix A.)

INTERIM OPINION

These proceedings involve adopting standard offers based on long-run avoided costs for power purchase contracts between the three largest electric utilities and qualifying facilities (QF). The utilities are: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E).

Before explaining the procedural history which has brought us to this point, we think it is constructive to explain briefly why we have pursued developing such standard offers in view of the standard offers in-place which pay QFs for their power based on actual short-run utility avoided costs.

I. SUMMARY OF DECISION

This decision authorizes what is termed Standard Offer #4, which has different payment options for QFs, all of which are based on forecasts of the utilities' resource mix and costs. The three payment options under Standard Offer #4 resulted from negotiations. A negotiating conference, which lasted five weeks, was held at our direction, with vigorous participation by utilities, QFs, and our staff. We have committed to hold evidentiary hearings, which almost all parties desire. However, there is substantial agreement among utilities, QFs, and our staff that until a more permanent solution is found for the complex task of fairly valuing and pricing QF power over the long-run, Standard Offer #4, with three payment options, should go into effect.

We undertook the negotiating conference in the hope of coming closer to an interim solution which, while not perfect from all perspectives, could be useful for QFs and utilities. While some may have hoped to accomplish more than the scope of the consensus reached, or they would have preferred different results, we think the negotiating conference was extremely fruitful.

The negotiated standard offer and three payment options are approved, with some reasonable restrictions on their use set by us under our prerogative.

Standard Offer #4, at this juncture, is interim in the sense it may ultimately be replaced with a different costing methodology, contract terms, etc. However, until that happens, it may be fully relied on by utilities and QFs who find the options useful. Those who contract under interim Standard Offer #4 will not be subject to having terms or prices changed later, except as narrowly and specifically ordered by this decision. Any changes made to this standard offer in the future will only apply to those contracting after such changes. Potential QFs who find they cannot use Standard Offer #4, as approved today, still have the option of pursuing a negotiated nonstandard contract with utilities.

II. BACKGROUND

Utilities' short-run avoided costs have proven to be more volatile than many observers would have guessed. We have seen a drastic run-up in fuel oil and gas prices, followed by a moderate decline in oil prices. The QF industry contends that the price uncertainty posed under the existing as-available and firm capacity standard offers, both based on short-run avoided costs, makes it extremely difficult to arrange financing for potential QF projects. QFs tell us that those who hold the financing purse-strings, both lenders and equity investors, are reluctant to commit captial when a project's payment stream is so uncertain. Our Decision (D.) 82-01-103 in OIR 2, issued January 21, 1982, recognized the need to pursue developing standard offers based on long-run avoided utility costs (page 67, mimeo.). Oil and gas prices were steadily rising when that decision was issued, and although the three largest electric utilities were ordered to file applications with proposed standard offers based on long-run avoided costs, most of our attention and that of the QF industry was directed to perfecting standard offers based on short-run avoided costs. Many assumed oil prices would continue to rise; few seemed to believe they would start a decline. As oil prices started to decline the intensity of interest in standard offers which would produce prices based on long-run (and presumably less volatile) avoided costs correspondingly increased.

If we do not adopt a standard offer based on long-run avoided costs as an alternative to the existing standard offers, the pressure

for nonstandard contracts between utilities and QFs could steadily increase. Such nonstandard contract negotiations pose problems for all: QFs typically ask for variations of up-front price security or certainty so they can finance projects, and utilities are faced with ensuring the nonstandard contract has suitable terms to make it a secure venture for them and their ratepayers; further, operating under our regulation, utilities are concerned about ultimate cost recovery, and worry that the prudence of nonstandard contracts may be successfully challeged in their energy cost recovery proceedings. Also, the long-term value of new QF capacity in the utilities' resource plans is not fully reflected by the existing standard offers which base prices on fluctuating short-run avoided utility cost (see D.82-01-103, p 67). It is, then, in everyone's interest that a standard offer based on long-run avoided cost be adopted.

The threshold problem is how can long-run avoided costs be determined. Dealing with short-run avoided costs was difficult, but the problems were surmounted and standard offers are in place. However, to value QF power reasonably in the long run, we must make many assumptions about the utilities' future generation mix and costs. While we deal extensively with forecasting the future when ratemaking, the view is only 1-3 years. This does not mean we cannot project the value of QF power for longer periods, say 10-15 years; but it means that the method used to forecast the value of QF power must be one that is not biased at the outset with a likelihood of being too high or too low when, after the test of time, payments to QFs under the forecast are compared to actual avoided costs. Or, from the ratepayer's perspective, there must be an even chance that the forecast will be too high as too low.

There are different ways of arriving at estimates of long-run avoided costs, and the future value of QF power, but all involve proxies or the creation of a utility's generation mix and costs on a composite basis viewed at some future time. The "generation resource plan" approach, for example, would evaluate the (weighted) capacity and energy costs associated with the utility's projected mix of resource additions without the availability of QF power. Some (not the utilities) prefer using a coal plant as the

assumed resource addition that would be deferred by long-term QF power. Another method, discussed later in this opinion, is forecasting short-run avoided costs into the future to capture a proxy of future conditions. Under this approach, the value of QF power is computed on the general assumption that the utility does not make any new plant investments except in some short run peaking capacity to maintain system reliability. Once this value is quantified then various options for paying QFs for their value are applied. Obviously, the longer the forecast the more problematical it is to rely on for valuing QF power and paying QFs, in that we are committed to treating the prices paid under the standard office as per se reasonable, to be passed on to ratepayers.

Some may contend that prices fixed under long-term forecasts can, at least at times, be above actual avoided costs, and therefore both: (1) PURPA will be violated in that payments will exceed avoided costs, and (2) the ratepayers will pay too much. We think the proper view and test is whether over the course of a long-term contract, despite periodic swings in actual avoided costs both above and below a forecast, the prices reasonably compensate QFs for their value in avoiding a utility's costs, and keep the ratepayer economically indifferent to whether the generation was performed by the utility or a QF. As long as there is equal likelihood that swings in actual avoided costs are both below and above the forecast, over the term of forecast based prices, we think the spirit and letter of PURPA are followed.

More troublesome, perhaps, for some is that we are adopting long-term standard offers based on forecasts of escalating avoided utility costs when there is no current capacity shortage among California utilities. The question becomes: why stimulate QF projects which cannot now proceed in the generation marketplace, under the existing as-available or firm capacity offers based on short-run costs, by adopting offers based on long-run utility avoided costs? The answer is that standard offers based on long-run avoided costs are for long-term contract commitments. We would rather err on the side of trying to have QF capacity steadily come on line over time, than on that of ultimately risking a critical capacity shortage because we did not take reasonable steps to afford an opportunity for QF power, particularly long-

term capacity, to be steadily developed. Many of the QF projects that may materialize because of the standard offers we adopt today may not come on line for several years. Also, developing QF power means California will be better able to meet its power needs from within its borders, and the State's resources will be more fully and efficiently used. Finally, we have never said that QF power must be developed at *any* cost, but rather that it should be developed with reasonable cost to ratepayers when viewed in the longer-term perspective. In the long run, if we do a reasonable job of valuing and pricing QF power, the ratepayers should be indifferent as to whether eventually needed capacity is supplied by QFs or electric utilities.

III. PROCEDURAL HISTORY

A. General

A first prehearing conference was held on July 19, 1982 before Administrative Law Judge (ALJ) Myers. Although hearings were not scheduled, procedural issues were raised. On November 18, 1982 we issued a report on the general issued involved in devising standard offers based on long-run avoided costs, and requested comments. We did this primarily to stimulate thinking among the parties on these issues, and to see if there was any consensus on the very tentative conclusions we had reached at that time. Eighteen parties filed comments. Then, on May 4, 1983 we issued D.83-05-038, which set a negotiating conference starting on May 23 at Hastings College of the Law. It was our hope that with good faith negotiations between the utilities, QF interests, our staff, and other interested parties, some tentative agreement could be reached about a standard offer(s); any agreed upon standard offer would, of course, require our ratification.

The ground rules of the negotiating conference were that any standard offers to be proposed to us for consideration should be completely worked out in final form, and that the assent of all interests at the negotiating conference was required before a standard offer would be proposed; this was essential to protect the rights of all parties since there were no evidentiary hearings. The goal, among the parties, was to attempt to develop an interim standard offer which, while not perhaps the perfect preferred

solution from their individual perspectives, would be one which they could comfortably tolerate and work under while refinement and "perfection" could be pursued in subsequent evidentiary hearings. Their understanding, based on our procedural plans as communicated by our ALJ, was that if we approved an agreed upon standard offer it would be an interim measure, subject only to change prospectively after formal hearings. It was also understood that the "final" Standard Offer #4 resulting from evidentiary hearings could, if appropriate after further evaluation, be based on an avoided cost methodology and/or pricing structure that differs from the interim order.

The negotiating conference concluded on June 24, 1983. The ALJ directed the three utilities to amend their respective applications no later than July 11, 1983; their amendments would contain proposed standard offers, complete with contract language, that precisely reflected the consensus agreement reached at the negotiating conference. The ALJ then set a second prehearing conference on Friday, July 22, 1983 to allow parties an opportunity to indicate whether the proposed standard offers should be allowed to go into effect by this Commission pending evidentiary hearings on the multitude of issues surrounding pricing QF power. Again, parties understood throughout the negotiating conference that if it produced some "negotiated" standard offers, which the Commission subsequently approved, they would be afforded an opportunity through the hearing process to propose modifications for prospective applications.

B. The Negotiating Conference Process

This was the first negotiating conference formally arranged and hosted by us. In some respects it is a frustrating process, because consensus building in a relatively unstructured arena (as compared to our hearing process) can be cumbersome. On the other hand, particularly if time limits are set, some consensus can be reached relatively quickly, whereas adversarial hearings on such a complex subject with a polarity of positions can take months longer. This is not to say the negotiating conference was nonadversarial; we understand it was adversarial. In fact, a critical ingredient of this process is that all sides are represented with near-equal resources and clout.

We were fortunate to have our staff coordinated and represented by the Director of the Utilities Division. We would be greatly concerned if our staff had not been an aggressive and key negotiating party, for it would raise the specter of utilities perhaps ultimately reaching the point with QFs of saying, in effect: your proposals do not sound fair, but since our cost recovery is virtually guaranteed if prices are paid under Commission ratified standard offers, what do we care—we will go along. However, neither consensus resolution of issues nor routinely seeking to split the difference, necessarily guarantees the best resolution from the standpoint of the public interest, which is why we must be guarded and very selective in deciding when to use the negotiating conference procedure, and in evaluating its results. We note from the prehearing conference that some QF representatives seem to feel that too much emphasis is placed on whether our staff, as a participant in negotiations, agrees on how an issue is resolved. Vigorous staff participation is an essential ingredient in any arena, and if some parties find staff's direct participation troublesome, it is probably a good indication our staff is doing the aggressive and thorough job we expect.

The most critical aspect of this process is that each agreed upon standard offer resulting from the negotiating conference is presented to us on a take-it-or-leave-it basis. Each was truly negotiated as a "package", comprised of cost forecasts, prices, and contract terms, etc. We are, at this juncture, without an evidentiary record upon which to weigh various proposals and adopt a standard offer reflecting a careful weighing of various components. Essentially, then, we face either accepting or rejecting each of the three standard offer payment options as negotiated, and we do not, in fairness to the parties, have the latitude to make modifications.

C. The Second Prehearing Conference

At the second prehearing conference on July 22, 1983 a number of QFs indicated that while there was substantial agreement that two of the payment options under Standard Offer #4 were complete and acceptable, there were serious reservations remaining with respect to:

1. Option #3, or the forecasted incremental energy rate option, as filed by PG&E and SDG&E; they found Edison's acceptable because they liked Edison's forecast.

2. Option #4, filed by PG&E only, which is a forecasted energy floor price payment option. This was an option not fully developed or addressed during the negotiating conference.

QFs, essentially, asked that the negotiating conference be resumed or that they be allowed to pursue ad hoc negotiations with utilities. They stated a preference not to pursue refining Options #1 and #2 until all issues, from their perspective, relating to all four payment options are resolved. Also, they expressed the opinion that the "Regulatory Authority" clause in Edison's and SDG&E's proposed standard offer must be eliminated, and the issue about contract switching must be resolved.

After conferring with the assigned Commissioner, the ALJ ruled that the prehearing conference would be continued to August 8, 1983, for the specific purpose of allowing utilities to address concerns QFs has about contract language pertaining to Options #1 and #2. Also, he announced that the QFs' request to reopen the negotiating conference would be addressed by the Commission in this decision. QF representatives then listed the particular contract language and areas which, from their perspective, needed nonsubstantive changes so the contracts, mechanically, conformed to the agreement reached at the negotiating conference. Given the list of specified contract language "problem areas", the ALJ directed the utilities to review their contract language with QFs and staff, and to distribute any revised page before the prehearing conference continued. They were directed not to "negotiate", but, rather, to work together to ensure that the contract language is clear and carries out the intent of the negotiated settlement. The ALJ announced that the Commission would address the interrelated issues of contract switching and the contracts' regulatory authority clause in its decision; those issues are discussed later in this opinion.

On August 8 the prehearing conference resumed. An opportunity was extended to all parties to address whether the proposed

Standard Offer #4 payment options should go into effect, whether evidentiary hearings should be held and, if so, what issues should be addressed. There was an array of positions on these matters, as well as on whether the negotiating conference should be reopened.

Edison and SDG&E think the three payment options proposed with Standard Offer #4 should go into effect, and that before hearings are held the reaction and experience under those payment options should be studied and evaluated. Neither utility proposed a floor price mechanism as PG&E did, and they think such a conceptual payment option needs considerable study. PG&E thinks all four of its proposed payment options should go into effect, and it too thinks we should hold off going to hearing until we gain some marketplace experience with interim Standard Officer [sic] #4. While some QFs think further negotiations on PG&E's incremental energy rate forecast would be fruitful (e.g., result in a more favorable forecast), PG&E indicates further negotiations would be futile (PHC transcript, page 156). Edison indicates that at some point the entire areas of costing methodology, payment stream options and, more narrowly security provisions for contracts, should be scrutinized in hearings.

Our staff thinks all the payment options, except the floor price mechanism proposed by PG&E, should go into effect on an interim basis. The floor price mechanism warrants thorough review from the standpoint of ensuring ratepayer economic indifference and protection, and staff believes some "workshop" forum in conjunction with or before evidentiary hearings might be fruitful. Staff is not convinced that this particular payment option can be quickly resolved by negotiations. Staff believes that further efforts at negotiating the incremental energy rate forecast of SDG&E and PG&E so they are acceptable to more QFs would probably not be fruitful. Staff thinks at this juncture the entire subject of costing methodology, valuing long-term QF power, and pricing streams should be the subject of evidentiary hearings.

The California Energy Commission and the State Solid Waste Management Board both want us to direct further negotiations aimed specifically at having SDG&E and PG&E develop incre-

mental energy rate forecasts more favorable to QFs, and adopting a floor price mechanism payment option.

None of the QF representatives who made statements at the prehearing conference had any objection to Payment Options #1 and #2 going into effect for all three utilities. They all thought Edison's Option #3 was acceptable, because they prefer Edison's incremental energy rate forecast over that of either SDG&E or PG&E. Contrary to the views of PG&E, SDG&E and Staff, QFs almost uniformly believe if we direct more negotiations on the incremental energy rate forecasts of PG&E and SDG&E the end result will be more favorable forecasts. We note at this juncture that if we ordered more negotiations on the incremental energy rate forecasts of only two of the three utilities, our action would be taken as a strong signal that we have reason to believe their forecasts are too unfavorable to QFs. We have no facts or evidence to lead us to such a presumption; all we know is that some QFs say they need and would prefer more favorable forecasts. QFs all seem to indicate that if we do not order further negotiations aimed at these forecasts, then we should authorize the incremental energy rate forecast payment option as proposed by SDG&E and PG&E because some QFs may be able to use those payment options.

QFs think the latest floor price mechanism payment option proposed by PG&E is acceptable, and that if we do not totally approve it, and direct the other utilities to include it in their respective standard offers, then we should at least clearly embrace the concept and direct it to be the subject of further negotiations.

Other points raised by some QF representatives are:

1. We ought to clarify whether utilities can still pursue nonstandard contracts with potential QFs who do not find one of the standard offers useful.

2. The question of whether QFs already under contract may switch to Standard Offer #4 should be addressed and resolved, preferably with the result being freedom to switch; and, likewise, whether subsequent versions of Standard Offer #4 that may result after hearings should then be freely available retroactively to QFs who signed a contract under negotiated Standard Offer #4.

Both issues are addressed later in this opinion.

Some QFs want evidentiary hearings, primarily to develop a permanent costing methodology for valuing long-term QF power, to resolve the need for security provisions in contracts, and to pursue adopting methodologies and/or forecasts that are readily verifiable. On this latter point, one goal almost all QFs share is having utilities use a common forecast of long-run marginal costs for pricing QF power and for utility resource planning purposes. This, they say, would result in QFs no longer being "whipsawed" by utilities, which are the ultimate data repositories, using different forecasts for different purposes.

IV. LIMITATIONS ON THE AVAILABILITY OF THE ADOPTED STANDARD OFFER AND CONTRACT SWITCHING

The standard offers we have already adopted are based on utilities' short-run avoided costs, and they set prices which can fluctuate, but which closely parallel actual avoided costs. However, the standard offer addressed by this opinion involve projections, assumed proxies, and payment stream certainty which can have a visible impact on electric bills. This standard offer is the first with such characteristics, and there will undoubtedly be refinements and modifications adopted, for prospective application, as time goes by and experience is gained.

We will adopt some overall limitations on the use of this interim standard offer in recognition that we are not convinced

that it is a permanent all-inclusive solution. Parties agreed, at the negotiating conference, to recommend that the negotiated standard offer be allowed to remain in effect at least six months, but no more than two years. It will probably be at least six months before hearings conclude, so we have no difficulty ordering the offers ratified by this decision to be in effect for at least six months, and until further order.

SDG&E requests that its forecast of marginal operating costs underlying its energy prices be used for a maximum of six months; that issue will be addressed later in this opinion.

Am important point for our resolution is whether existing QFs, already in production and under contract, should be eligible for the standard offer adopted in this decision. At the negotiating conference the utilities asked for some clarification, wanting to avoid a morass of uncertainty and contract administration problems. None of the participants had specific suggestions at the negotiating conference, but all seemed to want some clarity. ALJ Alderson promised to bring the matter to the Commission's attention for resolution.

In the past, when the entire subject of devising standard offers was in its infancy and the existing standard offers based on short-run avoided costs were evolving, we allowed QFs under contract to switch to the standard offer based on short-run costs which ultimately evolved (D.82-01-103, mimeo page 145); subsequently we said: "QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed" (D.82-12-120, issued December 30, 1982, in A.82-03-26 et al., mimeo page 118).

We think there are overall problems with contract switching, and the preferred approach in this instance, particularly since the standard offer before us is so fully developed with all contract terms and complete with fixed prices, is for QFs to evaluate it from the basis of making a long-term commitment, for a 15-year minimum term is involved. Accordingly, QFs who sign up under one of the options under this standard offer, albiet interim in one sense, will not be allowed to switch later; they must wait until the end of their contract term.

With respect to QFs already in production, we will allow them to sign up under this standard offer only if they are no longer under contract; QFs who have decided to produce under existing standard offers, and who entered a contract, should be bound by their decision.

Some standard and nonstandard contracts have provisions which allow QFs to elect standard offers which may be approved subsequent to their entering the nonstandard contract. However, the standard offer approved by this decision represents only an interim solution, subject to change after hearings, for prospective application. As such, since we are adopting a standard offer without an evidentiary record, we are not comfortable allowing QFs under contract, even nonstandard contracts, the switch. QFs under standard and nonstandard contracts, with provisions clearly allowing them to switch, may switch after a final standard offer comes into existence after hearing, but for the time being they will have to honor their commitment under the contracts they entered. A critical factor in our thinking is that this standard offer, and the procedures leading to it, resulted primarily from our goal to encourage *new* QF projects which have not yet obtained financing or otherwise entered a contract and started production.

Finally, we will limit the levelization payment option under this standard offer to new QF facilities or those which have never produced and sold power. This is because, with some reluctance, we approve the levelization option as a stimulus for *new* QF projects, and it is not reasonable for ratepayers to bear the cost of levelization in the early years to benefit a QF project or facility which has already managed to obtain financing and start production.

A subject so closely related to contract availability and switching warrants discussion at this point, is our concern about QFs breaching, or otherwise altering the contracts entered under Standard Offer #4.

PG&E's amended application summarizes the overall underlying concern about fixing QF payments based on a forecast or, for that matter, any proxy of anticipated utility avoided costs:

> "We can be certain that actual avoided costs will differ from the forecasts. Locking into a forecast in a rigid way assures that there will be economic losers—either QFs or ratepayers—in the future, because actual avoided costs will either be above or below the forecast. Staff believes that a disadvantaged party won't mind, because there had been an equal chance of being the economic 'winner' at the time the contract was executed. This is good theory, but it defies experience. If one party is seriously disadvantaged by a contract, it will have strong motivation to breach or alter the contract, regardless of how reasonable the contract appeared when it was signed.
>
> "Similarly, PGandE expects that if QFs are disadvantaged by the forecast price options, they will do everything possible to renegotiate, terminate, or otherwise escape their obligations. We have attempted to write the contract to avoid this, but with the amount of money potentially at stake, ways may be found. Conversely, if ratepayers are harmed, we expect accusing fingers to be pointed at PGandE and at the Commission. We trust a future commission would abide by a decision of this one and allow costs to be recovered." (PG&E amended application, Exhibit A, page 4).

We think, QFs may be "winners" at times and "losers" at others, when, at any point in time, originally forecasted avoided costs are compared to actual. However, the recent volatility in short term utility avoided costs caused by oil price fluctuations will probably be borne in mind by QFs electing one of the forecast based payment options under Standard Offer #4. Accordingly, we believe they will think long and hard before seriously attempting to terminate early or to breach their contract. However, we agree with PG&E that some QFs under long term Standard Offer #4 contracts may seek to get out of those contracts if actual avoided cost conditions, particularly over a fairly long duration, would be to their advantage (despite the potential for damages generally

and specific minimum damages clauses in some of the contracts).[1]

We think it is reasonable to order that utilities are under no obligation to enter into any power purchase contract, even under one of the otherwise available Commission approved standard offers, with a QF who has terminated early or breached under Standard Offer #4, payment options approved by this decision, if damages have not been collected. By damages we mean the utility either having collected at least the minimum damages, if the contract has a minimum damages clause, and foreseeable damages if their is no applicable minimum damages clause. Parties should honor their contractual commitments, and we think our making it unattractive for QFs to terminate or switch contracts is only fair, as it balances the risk ratepayers are assuming at the outset with this long-term, forecast based, fixed price, standard offer. While this issue was not specifically raised at the negotiating conference, we think it is our prerogative to take reasonable steps to minimize contract evasion; indeed, under the circumstances it is our duty to the ratepayers.

V. THE STRUCTURE OF STANDARD OFFER #4 AND FUTURE CONTRACT LANGUAGE CONSISTENCY

This opinion will address what is called Standard Offer #4, which contains several payment options. Standard Offer #1 was adopted by D.82-12-120, and is for as-available energy payments; #2 is for firm capacity, and #3 is for smaller QF projects (under 100 kW). The Standard Offer #4 contracts proposed by each of the three utilities has some common contract terms that apply for all options, and specific terms covering the individual payment options. The filed contracts are complete with the agreed upon forecasts, upon which prices will be paid.

Each utility chose its own format and contract language, with the goal, however, of all being consistent in substance (with the

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[1] Minimum damages clauses apply to capacity payments when the firm capacity option is selected for capacity payments, and for energy payments when a levelized payment option is selected. Aside from the minimum damages clauses, utilities may pursue foreseeable damages as apply in any breach of contract situation.

exception of certain agreed to utility specific terms, such as curtailment). As experience is gained with standard offers, and QF power purchase contracts generally, uniform standard contract language should be used by all utilities, except for terms which must clearly be utility specific because of substantitive differences. The convenience of standard language will greatly aid those who must review standard offers. We are disappointed this could not have been done for Standard Offer #4 in the context of the negotiating conference, but it appears time did not permit it. Rather than to simply pick one of the utilities' contracts and order that language used by the others, we will direct the utilities to work together, with our staff, in proposing one form of Standard Offer #4 with uniform language (except where terms must be utility specific). Six months will be allowed for this undertaking, and the product shall be presented during the subsequent hearings for review.

That, we think, is adequate time for the three utilities' and our staff to harmoniously come to some common terms. QFs will have an opportunity to address the uniform Standard Offer in subsequent hearings. Once adopted standard offers are uniform for all utilities, it will be far easier to review and consider proposed changes, and to subsequently review any filed standard offer contracts in the future for compliance with Commission directives. As it now stands, for example, we, our staff, and interested parties, must review three very thick contracts and engage in cumbersome, confusing and time consuming cross-checking. We think consistency would be an enlightened step which, in the long run, will work to everyone's advantage.

VI. RAMPED-UP AND LEVELIZED LONG-TERM ENERGY AND CAPACITY PAYMENT OPTIONS UNDER STANDARD OFFER #4 (OPTIONS #1 AND #2)

Two energy payment options under the standard offer were proposed which warrant separate discussion because they share the same costing methodology, but have different payment streams.

Option #1: Payment stream fixed for 10 years,[2] and follows a ramped-up forecast.

Option #2: Payment stream fixed for 10 years and levelized.[2]

A. Common Elements:

Before addressing the specific differences, (primarily the issue of security), we will describe the common elements.

Contract term: The minimum term is 15 years, and the maximum is 30 years (Utilities should amend their contracts to specify the agreed upon maximum term).

Operation date: The QF project must be on line within 5 years from the date the agreement is executed. However, the QF agrees to the payment stream, based on the forecast, when the contract is signed. This means utilities must have a 15-year forecast when the contract is signed to allow for a maximum 5-year hiatus before operation and payments start after contract execution. QFs can, however, under the negotiated standard offer, make an election within ninety days before production starts on whether they will be paid under the ramped-up or levelized forecast. Thus, while both payment streams are known and fixed when the QF signs a contract, a QF can hold off with its final payment stream election and evaluate its requirements and conditions shortly before production begins.

Forecasts Underlying Contract Prices: The total utility avoided cost underlying the payment streams is technically composed of two elements: (1) avoided shortage costs, related to the peaking capacity the utility can avoid (based on the rental value of a combustion turbine), and; (2) system marginal operating costs, called the "energy" portion of the total avoided cost.[3] The

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[2] Ten years if the contract term is 20 years or more, but ½ of the contract term if the total contract term is less than 20 years.

[3] The appropriate standard for evaluating future utility and QF projects is a forecast of utility's marginal energy cost plus shortage cost. This is only a proxy for a forecast of average marginal composite energy cost and capacity cost. The shortgage cost is not literally the "capacity"

forecasts accompanying the filed standard offers were agreed to at the negotiating conference; while some may think they are too high, and others that they are too low, nevertheless they were agreed to. Whether the forecasts should be revised, for prospective application to new contracts, can be addressed in the subsequent hearings. The following schedules show the forecast energy portion of the total avoided cost for each utility. For illustrative purposes, the table for PG&E shows the price by time of delivery as well as the annual average price, only the annual average prices for Edison and SDG&E are shown:

Pacific Gas and Electric Company
Forecasted Energy Price Schedule

Year of Energy Deliveries	Forecasted Energy Prices*, ¢/kWh						
	Period A (Winter)			Period B (Summer)			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	Annual Average
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.18
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in PG&E's standard offer; the time periods are subject to change in accord with how peak, partial peak, and off peak is defined in

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payment nor is the system marginal operating cost the "energy" cost, but that terminology has evolved into this long-run standard offer proceeding from the short-run standard offer proceedings. This is one complexity among many relating to avoided cost forecasting that will be addressed in the evidentiary hearings.

PG&E's tariff schedules applicable to large industrial customers.

PG&E, Edison, and SDG&E

Forecasted Energy Price Schedule, Annual Average

(¢/kWh)

Year	PG&E	Edison	SDG&E
1983	5.18	5.30	—
1984	5.47	5.60	5.90
1985	5.55	5.70	6.40
1986	5.79	6.00	6.40
1987	6.16	6.40	6.30
1988	6.70	6.90	6.70
1989	7.34	7.60	7.90
1990	7.84	8.10	8.60
1991	8.34	8.60	9.20
1992	9.01	9.30	10.00
1993	9.75	10.10	10.30
1994	10.54	10.90	11.10
1995	11.39	11.80	11.80
1996	12.24	12.60	12.60
1997	13.14	13.60	13.40
1998	—	—	14.20

The preceding schedules show the 15-year forecasts of avoided marginal energy costs, which is, of course, one component of total avoided costs.

In understanding how total contract prices are derived, it is critical to keep in mind there are a number of mix-and-match options for both energy and shortage cost or capacity payments. For example, a QF can elect to sell part of its output under the terms of one of the existing standard offers based on short-run avoided costs; if he did so, the energy sold under short-run as available or firm capacity standard offers, would be subject to price variation, whereas the portion sold under the forecast would have a fixed price. Also, different shortage cost or capacity payment options are available to QFs signing up under any of the energy payment options.

Capacity payment price: QFs may elect to deliver either firm or as-delivered capacity. The QF can select how much firm capacity he will be contracted to provide, and any excess deliveries will receive the as-delivered capacity price. These capacity payments are determined and paid under the same terms as those in existing Standard Offers #1 an #2, for as-available and firm capacity, respectively. Thus, firm capacity payments can be levelized as provided by Standard Offer #2, and are subject to the performance bonus when the QF demonstrates a firm capacity factor in excess of 85%; all capacity payments are made monthly.

The following table shows the annual average capacity payment in ¢/kWh for as-available capacity:

PG&E, Edison and SDG&E

Forecasted Capacity Price Schedule, Annual Average*
(¢kWh)

Year	PG&E	Edison	SDG&E
1983	.798	.799	—
1984	.867	.868	.700
1985	.924	.924	.740
1986	1.004	.993	.800
1987	1.084	1.073	.870
1988	1.164	1.153	.950
1989	1.255	1.244	1.020
1990	1.346	1.335	1.100
1991	1.438	1.439	1.310
1992	1.541	1.690	1.400
1993	1.643	1.804	1.500
1994	1.757	1.929	1.600
1995	1.871	2.055	1.720
1996	2.009	2.215	1.840
1997	2.146	2.352	1.960
1998	—	—	2.100

* For payment purposes the annual average rate will be converted to seasonal ltime [sic] of delivery rates consistent with the Commission approved method applicable to as-available capacity. The annual average rate expressed in ¢/kWh, rather then $/kWh, is developed for the utilities' capacity payment fore-

casts, applying their allocation factors and hours per period currently in use.

B. Forecasted Ramped-Up Payments Based on Energy or System Marginal Operating Costs (Option #1)

Option #1 is the ramped-up payment stream, with the payment varying with season and time of delivery. This provides a direct price signal to encourage peak period delivery by QFs.

During the fixed price period, (maximum 10 years) the QF receives a series of predetermined energy prices for production, broken down by year and costing periods. These fixed prices per kWh are paid regardless of whether the utility's actual avoided costs turn out to be higher or lower. QFs can choose to take a fraction (in 20% increments) of their energy payments under this option, and the remainder under the full short-run avoided costs applicable under Standard Offers #1 and #2. Oil or gas-fired cogeneration facilities are limited to receiving no more than 20% of their energy payments under the forecasted energy price option, with the remainder paid at the full short-run avoided operating costs under other existing standard offers, or under Option #3 (which is described later).

After the fixed price period, (e.g. 10 years) the QF receives payment for energy delivered at the full short-run avoided operating costs which are also paid to QFs under Standard Offers #1 through #3.

This option contains no discounts, requires no security, and has no formula for calculating damages in the event of nonperformance or breach.

C. Levelized Payment (Option #2)

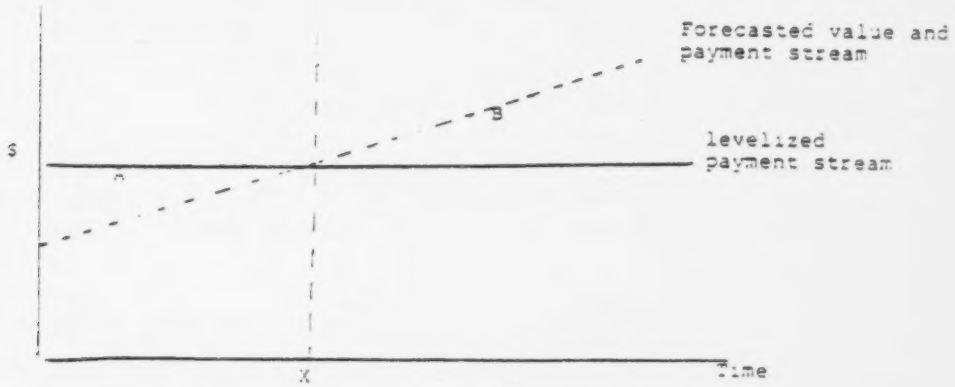
During the fixed price period, the QF will receive prices levelized over that period. The forecast from which these levelized prices are derived is the same as that used in the forecast or ramped-up energy price option. Prices are time-differentiated, and will be paid throughout the fixed price period. This option also does not require any discounts from the utility's avoided cost. However, it does require that the QF post security to protect ratepayers in the event nonperformance occurs and early period

overpayments have been made. And if the utility accepts a lesser grade of security, that may not fully guarantee protection of the ratepayer, then a 1.5% discount from the levelized prices is applied over the fixed price period (specifics concerning security and levelization are discussed below in this section). This option under PG&E's proposed contract, contains a formula for calculating minimum damages in the event of breach; however utilities may also seek to collect foreseeable damages allowed at law for breach of contract, beyond those specified by the formula.

1. Levelization

This is an opportune place to discuss levelization generally, because the distinguishing feature of payment Option #2 is a levelized payment stream.

Levelization is a payment stream where periodic payments are constant over a period of time, and are based on forecasted values and the value of money. It works roughly as follows:



The payor (e.g., utilities and ultimately their ratepayers) applies a discount rate to the ramped-up payment forecast in order to derive an "equivalent" levelized payment stream. As indicated in the above diagram, the result of levelization is that the payor pays a higher level of payments earlier in the time period (area A on diagram) in exchange for lower payments later on (area B on diagram). The payment streams are "equivalent" if, given the payor's opportunities to invest funds (or cost of capital), the savings in the later years (area B) are equivalent to the return that the payor could have earned investing the difference between

the forecasted and levelized payments (area A) early on. The discount rate is that rate of "foregone" compound interest at which the payor is willing to trade for the burden of paying more sooner than would otherwise be the case.

Applied to QF-utility contracts, levelization means the utility will be paying more in the earlier period, and electric rates for consumers in the early period will be incrementally higher as the periodic levelized payments are passed on in the utility's rates. Also, if the QF quits production before the end of the levelization overpayment, (time X on the above diagram), the utility and ratepayers are left having paid more than the commodity was valued. Our concern about levelization stems from these factors. In simplest terms, levelization for QF pricing is a form of ratepayer "loan" to make a perhaps otherwise nonfinanceable QF project viable enough to attract conventional financing. QFs say the option of levelization, which is comparable to ratepayers than their "financing" of utility-owned projects, is only fair. Staff thinks a solid QF project should be financeable if it has a guaranteed price stream, as under Option 1, and that a bank or other investor should make the "loan" needed in early years instead of the ratepayers. But staff agreed to this levelization option on an interim basis to see how effectively it facilitates new QF projects and to see how risky it actually is to ratepayers.

The discount rate negotiated at the conference, to be used in the utilities' levelization calculations, was 15%.[4] If something less than first class security (as discussed later) is put up by the QF to ensure ratepayer recovery for overpayments in the event of nonperformance, an additional 1½% is taken directly off the levelized payment stream to compensate ratepayers for the correspondingly higher risk resulting from a lesser grade of security. There was considerable debate among parties as to the appropriate "opportunity cost of capital" for ratepayers in levelizing payment streams for projects of varying technical and financial risk. If the discount rate used it too high, then ratepayers are not

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[4] PG&E included levelization based payments with both a 13½% and 15% discount rate; however, it shall use 15%, consistent with the agreement reached at the negotiating conference.

fully compensated for the overpayments in the early years of the contract; that is, the levelized payment stream is too high.

Levelization and its attendant problems posed by the use of discounting, security requirements and termination penalties is something which, in a perfect world, we would prefer not to deal with, particularly in the context of a standard offer. We have several concerns about levelization as a feature of even an interim standard offer:

(1) the precedent may lead parties to believe it is the norm;

(2) administering the security provisions of standard offer contracts with levelization can, as the number of QFs increase, be an ongoing administrative chore of some magnitude for utilities (which ultimately translates into additional costs to ratepayers); and

(3) costs to ratepayers from early contract period "overpayment" caused by levelization acerbates the overall level of electric rates, which are now higher than we prefer.

We wonder why a large number of QF projects cannot be financed with the simple forecasted payment stream, which is guaranteed, assuming performance, up to the first ten years of operation. The forecasted ramped-up payment stream offered by the nonlevelization option is a large step forward in terms of payment certainty for QFs, which should greatly assist with financing. The specter of many levelized standard offer contracts concerns us; particularly since we have no evidentiary record that shows solid viable QF projects cannot be developed or financed without levelization.

Our solution is to allow utilities to enter levelized standard offer based contracts for a maximum of one year after the effective date of the [sic] this order. As indicated in the following order, we will address lissues [sic] relating to this payment option as early as possible in evidentiary hearings. And lthis [sic] option may be extended though [sic] a subsequent interim order, if we determine that providing for levelization in a standard offer is in the continuing public interest. Those who represent QFs have the burden of showing why levelization is necessary. Our goal is not to

ensure every possible QG [sic] project and/or technology is financeable; rather, our goal is to provide an economic environment in which solid, well-conceived projects have a reasonable opportunity to be financed through prices paid by utilities and ratepayers. It is not our task to compensate, through standard offer payment terms, for all concerns and reluctance of lenders and equity investors. Ours is a world of risks, and we have no business ensuring that some have little or virtually no risk at the expense of others (i.e., ratepayers). While we will ratify the levelized option for use for one year, one purpose of this discussion is to alert parties directly that we have serious reservations about continuing to provide for levelization in a standard offer.

2. Security Provisions of Levelized Option #2

PG&E very aptly summarizes how the issue of security provisions evolved in the context of the levelization option:

> "This proved to be one of the most troublesome issues in the Settlement Conference. Commission staff wanted QFs to provide very solid, substantive security in order to assure ratepayers would be made whole in the event of termination or nonperformance. QFs wanted the opportunity to substitute lesser security (e.g., liens on their equipment) which is more readily affordable, and to allow utilities to exercise discretion in rejecting any 'inadequate' security that might be offered. Utilities were not anxious to have such discretion within a Standard Offer, because it appeared to present a no-win situation. The QF developer whose proposed security was rejected by the utility could complain that the utility was being unreasonable; if security that the utility accepted eventually turned out to be inadequate, its prudence could be questioned by the Commission.
>
> The result is a compromise. Two tiers of security will be accepted. QFs that provide first class security will be able to avoid price discounts; those that provide lesser security will be subject to a 1.5% energy price discount in the fixed price period. This lesser security—essentially corporate guarantees and equipment liens—is subject to acceptance by the utility. PGandE agreed to this discretionary authority because QFs

> insisted they needed the option of providing lesser security. PGandE reluctantly accepts this discretionary role in this Standard Offer and hopes that in any future recovery proceedings, the Commission will view its exercise of such discretion within the greater context of promoting alternative energy resources." (PG&E's third amended application, pages 15 and 16 of Appendix A).

The higher quality security, the amount of which changes each year as ratepayer exposure is reduced until the levelization mid or crossover point is reached, is any or a combination of the following: A letter of credit, performance bond, paid-up noncancellable project failure insurance or a solid corporate guarantee acceptable to the utility. Lesser security is other security which is acceptable to the utility, such as: a less solidcorporate [sic] guarantee, and liens or a mortgage on the facility and/or the land on which it is located.

Staff believes that if the utilities have discretion to reject second level security, that potential QFs should not be able to appeal the utilities' decision to the Commission. We agree. The ability to provide second level security is a major concession to responsibility of judging it. The utilities should not be second-guessed, and we do not want the responsibility for judging security in individual cases. We expect the evidentiary hearings to develop even clearer security requirements for this standard offer. A standard offer should not have discretionary iterms [sic] in it.

Having utilities administer these security provisions is directly analagous [sic] to their serving in the role as a lender, which in a real sense they are (with the ratepayers' money). We can understand their discomfort in this role, but we think the guidelines are clear enough they can reasonably administer the security provisions. Ultimately, however, we would prefer more concrete security provisions if levelization options are extended, and we expect this issue to be addressed in the evidentiary hearings. directly analogous to their serving in the role as a lender, which in a real sense they are (with the ratepayers' money). We can understand their discomfort in this role, but we think the guidelines are clear enough they can reasonably administer the security provisions. Ultimately, however, we would prefer more concrete security

provisions if levelization options are extended, and we expect this issue to be addressed in the evidentiary hearings. [sic]

D. Curtailment Provisions (Under All Payment Options)

The negotiated curtailment provisions for Standard Offer #4 are utility specific, with PG&E's provisions consisting of the following 2 options:

(a) Curtailment under "negative avoided cost" conditions and a lower "hydro spill rate" under hydro spill conditions with no hourly limit. This option refers directly to this Commission's definition of negative avoided costs and hydro spill conditions.

(b) A limit of 1,000 hours of real time prices per year for negative avoided cost, hydro spill and non-oil/gas units at the margin. This second option requires some further explanation, as PG&E explains:

"PGandE will not curtail the QF when these conditions occur, but will instead offer to continue purchases at a price equal to the current actual avoided energy cost. The QF can then make its own operating decisions; PGandE and ratepayers will be indifferent. PGandE will limit the 1,000 hours to off-peak periods, and increase the price in the other off-peak hours to account for the fact that these low-cost periods are no longer being averaged in.

"PGandE's unique system means it will have to have maximum operating flexibility in the coming years to efficiently utilize the available resources. The 1,000-hour option helps provide this necessary flexibility while remaining faithful to the avoided cost framework. SCE and SDGandE are not providing the opportunity for the QF to remain operational and receive actual avoided costs, but are instead offering annual hourly curtailment limits. PGandE does not believe such an approach is appropriate in its case, and would object to one being imposed". (PG&E's Amended Application, Exhibit A, pages 11-12).

SDG&E's negotiated standard offer includes provisions to curtail QF production for up to a total of 300 off-peak hours per year where such purchases result in "negative avoided cost" to SDG&E "as such term is defined by the CPUC (SDG&E's Amended application, page 22)."

Edison's offer curtails the QFs production for up to 300 off-peak hours when:

> "(i) purchases would result in costs greater than those which Edison would incur if it did not purchase energy from seller but instead utilized an equivalent amount of energy *generated from another Edison source* (emphasis added), or
>
> "(ii) the Edison Electric System demand would require that Edison hydro-energy be spilled to reduce generation". (Edison's Amendment, page 26)[5]

In D.82-01-103, D.82-04-071, and D.82-12-120, we defined "negative avoided costs" as a situation where, due to operational circumstances, purchases from QFs would result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. We cite such a condition as being when a baseload or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity but then cannot be restarted and brought up to its rated output for the next day's peak load, thus necessitating instead the start-up of a plant with very high generating costs (e.g., a gas turbine peaker) or an expensive emergency purchase of capacity. In D.82-04-071 the Commission concluded that, while curtailment was not appropriate for hydro spill conditions, a lower "hydro savings" price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period. Proposals to restrict the number of hours that curtailment and hydro spill

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[5] The phrase "generated from another Edison source" is interpreted (by both SCE and the Commission) to exclude economy energy purchases. Hence, it conforms with Commission policy on this issue.

conditions apply were denied in D.82-01-103 and D.82-04-071. However, in D.82-12-120 we directed utilities to undertake studies which would be considered in reviewing future proposals to establish such limits.

Only PG&E's curtailment option a) conforms with our narrowly defined negative avoided cost and hydro spill conditions established for Standard Offers contracts #1 and #2. We acknowledge the nonconformity of PG&E's option b) and the other utilities' curtailment provisions with our previous decisions. However, we consider these disparities as part of the negotiation process and integral to the parties arriving at a negotiated "package". We alert parties that these provisions will be reviewed and evaluated for prospective standard offers in evidentiary hearings.

E. The "Regulatory Authority" Clause

Edison and SDG&E have what are commonly termed "Regulatory Authority" clauses, which allow for changing contract terms if directed by a regulatory agency. Edison's reads as follows:

> "This Contract shall at all times be subject to such changes as any regulatory agency may direct in the exercise of its jurisdiction. If there is any conflict between the provisions of this Contract and any changes directed by such regulatory agency, the Parties shall amend this Contract in a manner consistent with such regulatory changes."

Both utilities indicated they included this clause consistent with prior Commission directives with respect to earlier standard offers. PG&E indicated it was willing to drop this clause because it seems incompatible with a long-term forecast based and binding contract, particularly if this Commission clearly intends to allow utility cost recovery for prices paid under standard offer contracts.

In view of our holding that contracts entered under Standard Offer #4 will not be subject to retroactive change based on prospective developments in the continuing saga of pricing QF power, we think the regulatory authority clause should be deleted. In other words, the quid pro quo for giving QFs certainty with respect to all contract terms, and eliminating the regulatory

authority clause, is that QFs may not freely switch to other contracts later, until their contract term is up, if subsequent contracts or terms appear more favorable. Thus, we are really exchanging certainty of contract sanctity for certainty of commitment, and given our reaffirmation that cost recovery will be allowed utilities for all standard offer power purchase contracts, we think this is only fair. QFs contend that with the regulatory authority clauses in the contracts of Edison and SDG&E there will be insurmountable hesitation by lenders because of uncertainty. In ordering the clauses removed we recognize that we cannot order retroactive changes to interim Standard Offer #4 contracts but, given the restrictions placed on the use and availability of this negotiated standrd [sic] offer, we are willing to commit to that loss in flexibility.

F. SDG&E's Forecast of Marginal Energy Production Costs and Updating Forecasts

SDG&E requests that its 15-year forecast of marginal energy and production costs and its corresponding incremental energy rate be available to price QF power under this standard offer for a maximum of six months after filing its amended application which was filed on July 11, 1983 (SDG&E's amended application, pages 5, 9 and 12).

Near the conclusion of the negotiating conference there was disagreement about the energy rate forecast SDG&E would use in connection with its standard offer. Ultimately, SDG&E filed the forecast most parties thought was agreed to. It did this, according to its amended application, in the spirit of cooperation; however, it indicates its most current forecast is lower (SDG&E's amended application, pages 5-6). Proposing the consensus agreed upon forecast, one SDG&E prepared in March 1983, but requesting a maximum six month period for its availability for QF contracts, was done, according to SDG&E, at ALJ Alderson's suggestion. Our ALJ offered that suggested compromise as a means of avoiding what seemed to be a looming and substantial impasse.

We believe the substance of our ALJ's suggestion has merit. However, rather than impose a hard and fixed time cap for use of

SDG&E's filed forecast, we will direct that it be applied to Standard Offer #4 until further order; and one of the first issues we want considered at the evidentiary hearings, for expeditious consideration and decision, is the reasonableness of SDG&E's forecast, particularly vis-a-vis the level of Edison's and PG&E's. This approach is preferred because we do not want to get into the situation of having a hiatus, where prices based on SDG&E's filed forecast have lapsed, and a forecast to replace it has not been approved. Our solution reasonably addresses SDG&E's concern.

We are not prepared today to address the related questions of the frequency of updating the forecasts of all utilities, and the procedural forum or vehicles for updating. Those are issues, however, that are deserving of all parties' attention during hearings. The forecasts underlying prices in interim Standard Offer #4, for the respective utilities shall, in the meantime, be used as directed in the following order.

VII. FORECASTED INCREMENTAL ENERGY RATE PAYMENTS (OPTION #3)

Capacity payments under this option are the same as those described for Option #1 and #2 (as discussed). However, the energy prices under this option are based on (1) a *forecast* of the utilities' incremental energy rates and, (2) *actual* utility costs for incremental fuel. The incremental energy rate has been referred to by some parties as the derived and/or incremental heat rate, which is incorrect. The incremental energy rate is derived from marginal energy cost forecasts taken from utilities' production simulation models; these models include estimates of the costs of all projected resources at the margin over the term of the forecast. (e.g., 15 years). Once the marginal energy cost forecast is made it is then analyzed to determine the primary fuel for the resource most frequently at the margin, which has turned out thus far to be oil or gas. The overall annual marginal energy cost is then divided by the projected incremental fuel cost for that period to produce, for any given year, a forecast of the incremental energy rate (which is expressed in Btus/kWh). While this is similar to how heat rates are expressed, as derived it does not reflect a system incremental heat rate, because it is derived by only one fuel/resource and not a weighting of all resources that may appear

at the margin at times over the forecast period. For consistency among utilities, and to avoid prolonging confusion, this payment option shall be referred to as the "incremental energy rate" option, and their contract terms and language shall be amended accordingly.

Assuming oil or gas generation is the marginal, incremental, swing generation source, incremental energy costs for utilities are the product of the incremental energy rate and the price paid for oil or gas. This pricing formula and payment stream is most sought by oil and gas cogenerators, as while the forecasted utility incremental energy rate is fixed, the cost of fuel will be actual; and, of course, if the cost of utility oil and natural gas rises or falls there is a direct correlation for the QF's corresponding costs. PG&E likes this payment option because it thinks there is less likelihood, over time, that payments to QFs will deviate from actual realized utility avoided costs (PG&E's amended application, Exhibit H, page 9).

Under PG&E's Option #3[6] the QF will be paid a monthly incremental energy rate, based on a "derived" incremental heat rate forecast and the actual price of marginal fuel (i.e., natural gas or oil). However, there are revisions for making adjustments should PG&E's actual incremental energy rate differ from the projection. The QF, when the contract is signed, can elect a series of annual band widths, expressed in 100s of Btu/kWh, which are equally applied above and below the utilty's [sic] forecast of incremental energy rates. The lower band serves as a floor, and the upper band a ceiling. At the end of each year PG&E determines its actual price of oil and natural gas for its fossil fuel generating plants and divides this weighted cost into the energy payments made to the QF over the year. The result of this calculation is the utility's "actual" (derived) incremental energy rate. If the actual derived heat rate factor for the year is below the elected lower band, PG&E will make a one-time payment so the

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[6] Although PG&E's amended application calls this Option #4, for consistency with the other utility filings, and since PG&E's designated Option #3 is not approved by this decision, we refer to this energy payment Option as #3.

QF receives the value of the lower band for that year; if it falls above the upper limit of the band the QF makes a similar one-time payment to PG&E; finally, if it is within the limits of the band, no payment adjustment is made.

Other than the specifics described above, the contract terms for Option #1 apply to this option. Thus, this option contains no discounts, requires no security and, while probably most attractive to oil and gas cogenerators, is available to all QF technologies. Once the forecast based payment stream ends, the QF will receive the then current avoided energy prices.

PG&E proposes the one-time annual reconciliation adjustment, while Edison would simply compute the price and any adjustment monthly. PG&E explains why it has a different approach as follows:

> "PGandE's heat rate option differs from SCE's in that it contains a single value per year, rather than one for each costing period, and it applies annually rather than monthly. PGandE believes that these differences reflect utility-specific differences and that it would be inappropriate to require PGandE to adopt SCE's approach. Specifically, there appears to be an asymmetry across months for HFRs on PGandE's system. For instance, a typical year could see 2 or 3 months (in the spring) well below the annual fixed HRF, and the remaining 9 or 10 months near or slightly above it. Given a band of the proper width, this could trigger payments to the QF in the spring, with no compensating payments the rest of the year. PGandE could develop a monthly mechanism such as SCE's; however, we believe that a) it would by unnecessarily complex, b) PGandE's structure provides sufficient pricing certainty for QFs, and c) further analysis would be required, and lower HRF [sic] values would likely result." (PG&E's amended application, Exhibit A page 4).

We recognize the benefits of having oil and gas cogenerators on the system to displace the utilities' incremental oil and gas generation units, but only to the extent that: 1) cogeneration results in a more efficient use of fossil fuels (i.e., the cogenerator's

actual incremental energy rate is lower than the utility's) and, 2) California's resource base, no matter how well it can be diversified, may require some oil and gas generation units to meet demand. We are concerned, however, that this energy payment option could, over time, provide incentives to oil and gas cogenerators that are not commensurate with the benefits described above. Whereas Options #1 and #2 place the entire risk that a QF's actual production costs may be higher than our projections of avoided costs, Option #3 removes the risk associated with fuel-price variability from fossil-fuel cogenerators. Instead, ratepayers are exposed to all of the fuel-price variations, which can be very significant for oil and gas. Furthermore, providing a band around the incremental energy rate forecast mitigates some of the potential efficienty [sic] benefits that oil and gas cognerators [sic] can add to the system.

The issue of the utilitities [sic] forecast of incremental energy rates was not resolved at the negotiating conference to the satisfaction of some QFs. At the prehearing conference QFs indicated they found Edison's filed forecast acceptable, while PG&E's and SDG&E's were not. QFs request to reopen the negotiating conference to pursue what, from their perspective, would be a "better" forecast from PG&E and SDG&E. So, at this juncture, we see our choices with respect to payment Option #3 of being the following: 1) To approve Edison's Option #3, and reopen the negotiating conference to consider further the other utilities' forecasts; 2) to put all these forecasts back into the negotiating conference; 3) to allow this payment option, for all utilities, to be taken up in evidentiary hearings and approve nothing today with respect to Option #3 or, 4) to approve the use of Option #3 for all utilities, as filed, on the positive assumption that some QFs may find it useful pending a complete review of Standard Offer #4 and all payment options during evidentiary hearings, during which the feasibility of further negotiations is always an option.

We think the latter approach is by far the most constructive in view of our policy reservations concerning this option and our decision, discussed later, not to reopen the negotiating conference (our reasons for not reopening the negotiating conference are

discussed later). QFs, we note, who are dissatisfied with the incremental energy rate forecasts may compensate to some degree by selecting a wider band around the utility's forecast; thus, while their minimum payments could be lower, their potential maximum payment could be higher. In any event, we find allowing this payment option to go into effect extends to QFs another option and opportunity not now present. Even if only a portion of oil and gas cogenerator QFs can use this option, it is a material improvement over not having the option available. Also, as discussed later, QFs may seek a nonstandard contract if they find Option #3, or any other option or standard offer, does not suit their needs. The continued availability of nonstandard contracts is discussed later in this opinion.

In view of the reservations discussed above, we are limiting the availability of this energy payment option to a maximum of one year after the effective date of the following order. As we determined for payment Option #2, we will not extend that period for payment Option #3 until evidentiary hearings have addressed these issues and we determine that continuing an incremental energy rate option beyond one year is in the public interest.

VIII. UTILITY COST RECOVERY OF PRICES PAID UNDER STANDARD OFFER CONTRACTS WITH QFS

At the negotiating conference the utilities raised concerns about their cost recovery in Energy Cost Adjustment Clause (ECAC) proceedings, assuming we approve the negotiated interim standard offer. They repeat the concern in their amended applications.

We thought it was well understood that prices paid QFs under standard offers approved or mandated by us were per se reasonable for ratemaking purposes. That is one of the hallmarks of the standard offer. It would be inconsistent and unfair for us to approve the use of a standard offer and later question the reasonableness of the prices. While the world may not always be fair, in our regulatory realm this Commission would never subsequently disallow costs necessarily incurred to pay QFs under

standard offer contracts which we expressly found reasonable at the outset.

The only possibility for an ECAC ratemaking adjustment would be if a utility did not diligently enforce all contract provisions which protect the ratepayers. For example, in the event of QF breach or nonperformance, we can easily foresee a ratemaking adjustment if the utility did not take all reasonable measures to collect damages or to have security called on and applied to mitigate a loss; damages and called upon security inure to the ratepayers by a credit to the ECAC balancing account. We would be derelict if we did not ensure utilities remain diligent in administering power purchase contracts on behalf of their ratepayers.

But, with respect to the utilities' greatest concern, we can only say that we cannot envision this Commission, or its successor members, ever being so patently unfair as to attempt to disallow prices paid QFs under Commission approved standard offers.

IX. CONTRACT TERMS OF INTERIM STANDARD OFFER #4 SUBJECT TO RETROACTIVE INCORPORATION RESULTING FROM A.82-03-26 ET AL.

Since the regulatory authority clause of Standard Offer #4 is being eliminated, we must be very specific about any contract terms that are subject to retroactive change. Much of Standard Offer #4 contract language was premised on existing Standard Offers #1 and #2, which will be subject to another order in A.82-03-26 et al. Although Standard Offer #4, as proposed, is very inclusive, there are certain contract terms which should be reasonably consistent with other standard offers; we can direct consistency without changing the substance of negotiated Standard Offer #4. Those contract terms fall in the categories of:

(1) PG&E's line loss factor (PG&E only).

(2) Interconnection procedures and requirements involving lfuture [sic] line and system upgrades.

(3) Right of first refusal and right to purchase on abandonment.

(4) Insurance requirements.

We are aware, however, of the difficulty for some QFs to proceed with their projects without a definite clarification of these final contract terms. We anticipate a decision on A.82-03-26 in the near future. However, for those contracts signed by both parties prior to the effective date of a decision on A.82-03-26 et al. with respect to these terms, we will grant the QF discretion to decide, within 30 days after the effective date of our decision on A.82-03-26, whether or not the terms shall be retroactively changed in his/her contract. In this way, a QF that is ready to proceed immediately following this order will have the definitive contract terms with which to approach financial institutions and the option to have them changed retroactively. However, for any contract signed by both parties after the effective date of our decision on A.82-03-26, we order utilities to amend their respective Standard Office [sic] #4 contract language and terms, for retroactive application, on the above points consistent with the outcome in A.82-03-26 et al. No other terms shall be changed by order of this Commission for retroactive application to executed Standard Offer #4 contracts.

X. OPPORTUNITY FOR NONSTANDARD CONTRACTS BETWEEN UTILITIES AND QFS

During the prehearing conference QFs asked that we address whether utilities may still negotiate nonstandard contracts if proposed Standard Offer #4 goes into effect. Our original direction on this point in D.82-01-103 remains in effect; that is: utilities shall negotiate in good faith with potential QFs who do not want to contract under a standard offer. We expect utilities to continue to abide by that order. We recently addressed and amplified some significant procedural and substantive points relating to nonstandard contract negotiations, which are worth mentioning again for the benefit of all parties (D.83-06-109, in C.83-05-12, *Friant vs PG&E*, pages 4-5):

> "... Utilities were told to negotiate proposed nonstandard contracts in good faith with QFs not wanting to accept a standard offer, but we did not mandate a result. The mandated obligation in terms of end result which utilities do have

is to contract under the applicable adopted standard offers. As long as utilities negotiate in good faith with respect to nonstandard contracts, they fulfill our mandate with respect to those types of contracts. If we allow QFs seeking nonstandard contracts to bring their preferred proposals before us for ratification, instead of utilities applying for approval only after their management thinks a nonstandard contract has merit but wants our ratification in view of cost recovery concerns, the entire negotiating process would take a very different turn from what we envisioned. For then, QFs and utilities would in essence ultimately 'negotiate' with us, and not each other. We refuse to so directly interject ourselves into the arena of QF-utility negotiations. Accordingly, we will not order a 'result' based upon a QF's complaint, but we will impose sanctions on a utility for bad faith negotiations.

"Although the distinction we draw may seem too subtle or without solid basis from Friant's perspective, it is deeply rooted in the role of the regulator vis-a-vis investor-owned public utilities. For ordinarily, in the absence of compelling circumstances, utility management should apply its expertise and judgment within the regulatory parameters we set; we must ensure the parameters are fair and in the overall public interest, but we should not directly 'manage.' By the nature of the relief Friant requests it is asking us to substitute our judgment for that of the utility's management. We will however make a ratemaking adjustment if we find a utility had a lower cost option for power (e.g. QF power) which it did not exercise, or otherwise acted imprudently."

XI. REOPENING THE NEGOTIATING CONFERENCE AND SCHEDULE FOR EVIDENTIARY HEARINGS

QFs want to reopen the negotiating conference to pursue different derived heat rate forecasts from PG&E and SDG&E with respect to payment Option #3, and to develop a fourth payment option.[7] We have decided not to reopen the negotiating

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[7] Early in the negotiating conference PG&E proposed an energy floor price mechanism, which had a fixed price period and a discounting mechanism in later years to compensate for the guaranteed floor price

conference, but as the evidentiary hearing proceeds, we leave it to the assigned Commissioner to determine whether any negotiations regarding Option #3 will contribute to the ultimate decision affecting the future of Option #3 beyond the one-year period provided by this order.

When we announced the settlement conference we stated it would run for four weeks. Our ALJ allowed it to go for five weeks. We knew at the outset some parties, at the conclusion of the negotiating conference, would probably either be dissatisfied with the results or want it to go longer if not everything was "settled". That's the essence of a negotiating session; there are inherent frustrations built into that process.

The negotiating conference required a lot of staff expertise and the participation of our Utilities Division director. Five weeks is enough. Also, a negotiating conference should be held for only the period specified at the outset, otherwise parties will, for good reason, have the expectation that if they do not like the results the conference can go on and on until they do. And there is always the real, but undesirable, possibility of Parkinson's Third Law starting to apply when we hold negotiating conferences, which, in

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during the fixed price period. Then, very late in the negotiating conference, a variation was proposed by U. S. Windpower, but was not developed to the point of the various parties (utilities, staff and QFs) being able to reach a consensus. Of the three utilities, only PG&E developed this payment option in the amended applications. Edison and SDG&E, as our staff, think the concept may hold some promise but that it needs considerable study. Whereas all the other payment options have prices that are based either completely or substantially on a fixed forecast, PG&E's proposed floor price mechanism makes payments to QFs, over time, based on actual utility avoided costs. However, in the early years of the contract the prices can set as a floor which can be *above* the levelized payment stream prices in Option #2; there is a long payback period provided for in later years if early year payments substantially exceed actual avoided costs. The payback period, depending on the contract term and amount of overpayment, can by substantially longer than the payback period in Option #2. Thus, despite discounting factors in later years, the issue of risk assessment and security provisions become even more critical for this proposed payment option than Option #2.

essence, is: work always fills the time allowed for it. Another aspect of reopening the negotiating conference for the specific purposes proposed by QFs is that it would tend to be taken by all parties that we strongly expect a certain result (e.g., that SDG&E and PG&E should raise their derived incremental energy rate (forecast), or that we conceptually embrace a payment option, such as the floor price mechanism. We have no reason to believe any of the energy rate forecasts are too low (or for that matter too high), or that the floor price mechanism payment option has conceptual merit. Taking the extraordinary step of ordering negotiations reopened under these circumstances would not do justice to the concept of allowing parties a fixed time to reach a negotiated consensus. As this is our first experience with a negotiating conference in a generic and complex proceeding, and substantial results have already been accomplished, we do not think it is either necessary or desirable to reopen it. We are sorry if some are disappointed by our decision on this point, but as we said earlier, that's the negotiating process.

We would have been surprised had some not been disappointed. At this juncture we think it is most constructive for parties to spend their time to start preparing themselves for evidentiary hearings, so their prepared showings are complete and well developed. They are free, in doing this, to exchange ideas and concepts.

To ameloriate some frustration, disappointment, and possible economic forebearance, we are, as discussed above, authorizing the incremental energy rate payment Option #3 for all three utilities, and not just Edison, so that option is extended throughout most of the state.

All parties must realize that while we are approving the negotiated standard offer, they should not assume the methodology underlying the derived prices and the contract terms have significant precedential value in our continuing process of adopting a standard based on long-run avoided costs. When evidentiary hearings begin, parties should be prepared to examine and address all the concepts embodied in the negotiated standard offer.

When should evidentiary hearings begin? Some parties, as discussed above, are extremely anxious for hearings to start almost immediately; the utilities would prefer a pause, in essence to catch their breath and gain some experience with the negotiated standard offer. While we are anxious to proceed with our continuing and evolving endeavor of valuing and pricing QF power, and establishing a lasting standard offer based on long-run avoided costs, we think it would be very useful for the parties to digest, evaluate, and reflect on what has been done thus far in preparing for hearings. Hearings, we believe, should start in early 1984, with another prehearing conference in December of 1983. The prehearing conference will be set by a separate notice.

XII. EFFECTIVE DATE OF THIS OPINION AND ORDER

We think that Standard Offer #4 and its three payment options, which are approved and adopted by this opinion and the following order, are a significant step toward valuing and pricing QF power over the long term. QFs have gained some more standard offer options, which can only help stimulate new projects and facilities.

Given the consensus reached, we do not anticipate receiving applications for rehearing on this interim decision. Accordingly, we will make the following order effective the date of signature. We also do this because we think it is in the public interest to have Standard Offer #4, albeit a negotiated and interim standard offer, available for use as soon as possible. However, it is possible that applications for rehearing may be filed within the time period after the order's effective date as set out in Public Utilities Code § 1731, and we expect utilities not to actually enter or sign contracts under Standard Offer #4 for at least 30 days after today, and until any such applications for rehearing, if they are filed, are acted on by us. We take this measure as a procedural safeguard, in fairness to all parties, in view of our acting without an evidentiary record upon which to make findings of fact sufficient to issue a decision to withstand judicial review.

XIII. FINDINGS OF FACT AND CONCLUSION OF LAW

Findings of Fact

1. D.83-05-038 announced a negotiating conference for these consolidated proceedings. That conference was publicly noticed, open to the public, and lasted from May 23 through June 24, 1983.

2. The amended applications in these proceedings, with the changes noted on the record during the second prehearing conference, contain Standard Offer #4. That standard offer, and three payment options under it, are acceptable to the respective utilities, QFs, and staff, for interim use.

Conclusion of Law

The standard offers filed by the applicant utilities should be ratified for use by utilities and QFs in contractual power purchases, as authorized and restricted by the following order.

INTERIM ORDER

IT IS ORDERED that:

1. Standard Offer #4, Payment Options #1 through #3, as proposed by the Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison), shall be used by those utilities until further order of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order. However, in exercising those payment options under Standard Offer #4 the following restrictions or conditions shall apply:

   a. Qualifying facilities (QFs) who are under a power purchase contract with a utility, either a contract under a standard offer or a nonstandard contract, shall not enter a contract based on Standard Offer #4 until their existing contract term is up.

b. Only QFs who are not under contract and who have not completed their facility as of the effective date of this order may elect Payment Option #2.

c. The "regulatory authority" clause in SDG&E's and Edison's Standard Offer #4 shall be eliminated.

d. QFs who enter contracts under Standard Offer #4 will not be allowed to switch to a subsequent version of Standard Offer #4, or to other standard or nonstandard contracts, until the term of their contract is up.

e. Payment Options #2 and #3 shall be extended and exercised by utilities for a maximum period of one year after the effective date of this order.

f. The terms in Standard Offer #4, Options #4, Options #1, through #3, are subject to change and retroactive application in contracts signed by both parties after the effective date of a decision in A.82-03-26 et al., and depending on the outcome in that proceeding, with respect to:

1. PG&E's line loss factor.

2. Interconnection provisions involving future lines and system upgrades.

3 Insurance.

4. Right to first refusal and right to purchase and abandonment.

For contracts signed by both parties (QF and utility) prior to the effective date of a decision on the above terms in A.82-03-26 et al. the QF has the option of deciding to keep the terms as set forth in the signed contract if the QF notifies the utility of this decision in writing within 30 days after the effective date of the Commission decision on A.82-03-26.

g. PG&E shall use a 15% discount rate for its levelized payment stream under Option #2.

Any other ordered changes to Standard Offer #4 will be for prospective application only in new contracts.

2. A QF which enters a contract under Standard Offer #4, as approved by this order, may not switch to another contract until the term of its Standard Offer #4 contract has expired or it has terminated; if a QF terminates early by breaching the contract the utility is under no obligation to enter a new contract or to purchase the QF's power until: (1) minimum damages are paid if a minimum damages clause in the contract is applicable; or (2) if there is no applicable minimum damages clause, until foreseeable damages have been paid to the utility. The payment of minimal damages shall not discharge the breaching QF from ultimate payment of foreseeable damages caused by the breach. Utilities, on behalf of their ratepayers, shall vigorously pursue recovery of all foreseeable damages in the event of a QF breaching a power purchase contract.

3. Prices paid to QFs for power purchased under Standard Offer #4 provisions, and contracts as under any standard offer, will be recovered through the ECAC balancing account, and any collection the utilities make with respect to recovering for damages or called on security shall be credited to that balancing account. However, utilities will be subject to ECAC ratemaking adjustment if it is demonstrated they did not diligently enforce all contract provisions.

4. Another prehearing conference shall be scheduled and held before evidentiary hearings begin. Its purpose will be to determine the order in which issues shall be addressed, dates for exchanging prepared testimony, and to set hearing dates. The issues that shall be addressed as early as possible in evidentiary hearings, and which we may address by another interim order, are:

a. SDG&E's forecast of energy production costs.

b. Whether the levelized energy payment and the incremental energy rate payment options should be extended for Standard Offer #4 beyond the one year period as ordered above.

5. PG&E, SDG&E, and Edison shall confer among themselves and with our staff to devise uniform Standard Offer #4 contract language, except for the very few terms which must be utility specific due to different operating characteristics. They

shall jointly submit their proposed uniform contract language as a compliance filing in these proceedings within six months from today (making the filing with the Docket Office and serving all appearances). Their proposed uniform contract language shall not be effective or used in contracts until it has been approved by this Commission.

This order is effective today.

Dated September 7, 1983, at San Francisco, California.

I abstain.

/s/ PRISCILLA C. GREW
Commissioner

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

Commissioner William T. Bagley, being necessarily absent, did not participate.

APPENDIX A
Page 1

List of Appearances

Applicants: *Larry C. Mount,* Attorney at Law, for Southern California Edison Company; *Wayne P. Sakarias,* John R. Asmus, Jr., and Vincent D. Bartolomucci, Attorneys at Law, for San Diego Gas & Electric Company; and Charles W. Thissell and *Jo Ann Shaffer,* Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: *Roy Alper,* Attorney at Law, for Independent Power Corporation; Chickering & Gregory, by *C. Hayden Ames,* Attorney at Law, for Geothermal Generation, Inc.; Pillsbury, Madison & Sutro, by *Michael R. Barr,* Attorney at Law, for Pillsbury, Madison & Sutro; Hanna & Morton, by *R. Lee Roberts,* Attorney at Law, and Henwood Associates, Inc., by David Branchcomb, for Ultra Systems, Inc., and Occidental Geothermal, Inc.; *Donald C. Davis,* for Herzog Contracting Corporation; *Nicole A. Clay,* for San Diego Energy Recovery Project (SANDER); *Frank F. Duquette,* for McDonnell Douglas; *Joseph Egan,* for University Energy; *Paul H. Eichenberger,* for SAI Engineers, Inc.; *Mark R. Farman,* for Resource Management International, Inc.; *Michel Peter Florio,* Attorney at Law, Jon Elliott, and Sylvia Siegel, for Toward Utility Rate Normalization (TURN); Lee Freeman, *Douglas Porter,* and Jon Castor, Attorneys at Law, for Pacific Lighting Energy Systems; *Janice G. Hamrin,* and Dan Richard, Attorney at Law, for Independent Energy Producers Association; *Richard C. Hill,* for Tosco Corporation; Nossaman, Guthner, Knox & Elliott, by *Peter C. Hoffman,* Attorney at Law, for Applied Power Technology, Inc.; *Neal A. Johnson,* for California Solid Waste Management Board; *Jim Kaiser,* for Sierra Energy and Risk Assessment; *Laura B. King,* for Natural Resource Defense Council; *Jane S. Kumin,* for Natomas Company; *C. M. Laffoon,* for Geothermal Generators, Inc.; *Mark Lyons,* Attorney at Law (New York, Washington, D.C.), for Ultra Systems, Inc.; P. R. Mann & Associates, by *Philip R. Mann,* Attorney at Law, for California Manufacturers Association; *William B. Marcus,* for California Hydro Systems, Inc.; *Kenneth R. Meyer,* for Energy Consulting Group; *Martin C.*

Recchuite and Michael J. Myers, Attorney at Law, for ARCO Solar, Inc.; Brown, Vence & Associates, by *Tom Reilly,* for Brown, Vence & Associates; *Donn Ruotolo,* for Ebasco Services, Inc.; *James Samis,* for Thermonetics, Inc.; *Gary D. Simon,* for Sigma Group; Graham & James, by *James D. Squeri,* Attorney at Law, for Union Oil Company of California; Messrs. Downey, Brand, Seymour & Rohwer, by *Philip A. Stohn,* Attorney at Law, for Federal Paper Board, Inc., and Sutherland, Asbill and Brennan, Attorneys at Law; William E. Swanson and *Jasper Williams,* Attorney at Law, for Stanford University; *Randall M. Tinkerman,* for American Energy Projects, Inc.; *Frederick S. Waiss,* Attorney at Law, for Stauffer Chemical Company; *Gregg Wheatland* and Kathy Weinheimer, Attorneys at Law, for California Energy Commission; Cooper Engineers, by *Mark White,* for West County Agency; *Harry Winters,* for University of California; *Matthew J. Wristbridge,* Attorney at Law, for General Electric Company; *Donald G. Salow,* for Stone & Webster; *Margaret E. Rueger,* for U. S. Windpower, Inc.; and *Reed V. Schmidt* and *Norman Ross Burgess,* for themselves.

Commission Staff: *Brian T. Cragg,* Attorney at Law, and *John D. Quinley.*

(END OF APPENDIX A)

APPENDIX C

Decision 83-12-050 December 20, 1983
Before the Public Utilities Commission
of the State of California

Application 82-04-44
(Filed April 21, 1982; amended April 28, 1982,
July 19, 1982, July 11, 1983, and August 2, 1983)

Application 82-04-46
(Filed April 21, 1982; amended May 12, 1982,
July 11, 1983, and August 10, 1983)

Application 82-04-47
(Filed April 21, 1982; amended
July 11 and August 2, 1983)

Second Application of Pacific Gas and Electric Company
for Approval of Certain Standard Offers Pursuant
to Decision No. 82-01-103 in Order Instituting
Rulemaking No. 2.

And Related Matters.

(See Decision 83-09-054 for Appearances.)

OPINION ON PETITIONS FOR MODIFICATION OF DECISION 83-09-054

On September 7, 1983 we issued Decision (D.) 83-09-054, which was an interim decision, adopting three payment options for Standard Offer No. 4. These options are to be used by the three applicant utilities in these consolidated proceedings. Our decision followed after a five-week negotiating conference and, subsequently, a prehearing conference lasting two days.

Petitions for modification were filed by the Independent Energy Producers (IEP) and Occidental Geothermal, Inc. (Occidental); a response to both petitions was filed by Southern California Edison Company (Edison), and IEP responded to Occidental's petition.

Occidental's Petition

Occidental points out that our D.83-09-054 directed the utilities to delete the regulatory authority clause, but that Edison's contract contains another clause, termed the "amendment clause" which Occidental thinks could have substantially the same effect as the regulatory authority clause that was deleted. We ordered the regulatory authority clause deleted to afford qualifying facilities (QF) the certainty and sanctity of contract terms and fixed term prices they wanted, but in exchange we did not allow subsequent contract switching. The regulatory authority clause, of course, could have allowed us to essentially change contract terms retroactively. Edison's response is that although the "amendment clause" would apply only if both Edison and the QF agreed that there was a "change in circumstances" necessitating a change in the contract terms, it does not object to removing the clause if keeping it in the contract alarms QFs. We will direct Edison to remove the amendment clause from its Standard Offer No. 4.

The second point raised by Occidental is that Edison's Standard Offer No. 4 is not clear that after the fixed price term or prior to the time of firm delivery, the QF will receive energy payments based on Edison's full avoided operating cost as determined now for Standard Offer No. 2 (for firm delivery based on short-run avoided cost). Edison's response on this point is essentially that it did not mean to build any ambiguity into the contract. It agrees to change the relevant contract provisions by inserting the language underlined below (see Attachment A-7 to Edison's response):

> Seller shall be paid a Monthly Energy Payment for Energy delivered by Seller and purchased by Edison at a rate equal to 100% of Edison's published avoided cost of energy <u>based on Edison's full avoided operating cost as updated periodically and</u> accepted by the Commission.

We think the amended contract language proposed by Edison in its response to Occidental's petition is clear enough. Occidental's expressed fear is that a future Commission may decide that QFs should be paid 80% of utilities' full operating costs, and that,

instead of 100%, only 80% would be paid by Edison. With Edison's proposed amendment all the Standard Offer No. 4 contracts refer to "full avoided operating cost." Because the fixed term is 10 years, it is extremely difficult to estimate what short-run avoided costs will be after that period. But it is clear QFs under Standard Offer No. 4 contracts will receive 100% of full avoided cost as those costs are then determined and accepted by this Commission. That is all the certainty contemplated at the negotiating conference, and it is all the certainty we can extend at this time.

Furthermore, on November 16, 1983, Occidental responded to Edison's response by applauding "Edison's good faith in making these important modifications." Occidental therefore seeks to withdraw its petition. IEP, similarly seeks dismissal of that portion of its petition supporting Occidental's petition. We will direct Edison to amend its contract language as proposed. No further amendment is necessary or appropriate.

IEP's Petition

IEP, in addition to supporting the points addressed by Occidental, takes exception to the procedure we set out in D.83-09-054 to initiate the process of having a standardized Standard Offer No. 4. We ordered the three utilities and our staff to work together to develop standard contract language, with the resulting proposed contract to be reviewed in subsequent hearings. While pleased with our effort for more standardization, IEP thinks QFs will be unfairly prejudiced by not being part of all meetings on the subject between the utilities and our staff.

We adopted the procedure because we thought it could expedite at least getting a work product for the many and various QF interests that are parties to these proceedings to review and react to. We thought the initial logistics for the undertaking, which is a complex task, would be more expedient: The many QF representatives will have full opportunity to review the work product filed by the utilities. Rather than modify the procedure, we suggest that our staff arrange an informal meeting with the utilities and QFs shortly after the utilities file the proposed standard language, which will be served on all parties. Thereafter, any remaining

concerns and issues can be more succinctly addressed during hearings. We will not modify the procedure as requested by IEP. We will, however, order the utilities to file the standard contract language six months from today.

Conclusion

Standard Offer No. 4, along with the energy price, incremental energy rate and shortage value forecasts adopted by D.83-09-054 has become effective. New incremental energy rates and/or avoided capacity cost values that may be adopted by the Commission in general rate case or ECAC proceedings will not affect the price forecasts established over the fixed payment term under Standard Offer No. 4, until further orders are issued in this proceeding.

No applications for rehearing were filed after D.83-09-054 was issued. We trust there will be no further petitions for modification of that decision, as parties should raise any concerns or proposals relating to Standard Offer No. 4 at the upcoming evidentiary hearing. We will be very reluctant to indulge any petitions that may address or propose piecemeal changes to existing Standard Offer No. 4, because it is being relied on by QFs and utilities alike. Efforts for ex parte modification only cloud an overall endeavor to bring some clarity and certainty so that the QF industry can analyze the standard offers available and make its choices. Procedurally, the next step for parties interested in this standard offer, and any changes for prospective application is to raise these points in the evidentiary hearings.

Findings of Fact

1. The modifications Edison proposes for its Standard Offer No. 4 contract, contained in its response to IEP's and Occidental's petition, are reasonable and should be adopted.

2. QFs are not unduly prejudiced or denied due process by the procedure D.83-09-054 established to have uniform standard contract language proposed.

Conclusions of Law

1. The petition for modification filed by Occidental should be granted, while IEP's petition should be granted in part and denied in part in accordance with our findings in this order.

2. The following order should be effective today to bring certainty quickly and enable QFs and others to expeditiously evaluate contract options.

ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall amend its Standard Offer No. 4 as it proposes in its response to the petitions for modification filed by the Independent Energy Producers (IEP) and Occidental Geothermal, Inc. (Occidental).

2. The petition for modification of Occidental is granted with respect to Edison's removing the "amendment clause" of its Standard Offer No. 4 contract, and it is granted to the extent of Edison's proposed modifications with respect to the energy price to be paid either before firm production or after the fixed price term.

3. IEP's petition for modification is granted with respect to Edison's being ordered to delete its amendment clause, but denied concerning its proposed modification of the procedure in Ordering Paragraph 5 of D.83-09-054.

4. The compliance filing ordered by Ordering Paragraph 5 of D.83-09-054 shall be filed no later than six months from today.

This order is effective today.

Dated December 20, 1983, at San Francisco, California.

I abstain because of reportable financial interest in potential small power producers.

/s/ PRISCILLA C. GREW
Commissioner

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

APPENDIX D

Decision 84-08-035 August 1, 1984

Before the Public Utilities Commission
of the State of California

Application 82-04-44
(Filed April 21, 1982;
amended April 28, 1982,
July 19, 1982, July 11, 1983
and August 2, 1983)

Application 82-04-46
(Filed April 21, 1982;
amended May 12, 1982,
July 11, 1983, and
August 10, 1983)

Application 82-04-47
(Filed April 21, 1982;
amended July 11, 1983
and August 2, 1983)

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters.

OPINION MODIFYING DECISION 83-09-054

By Ordering Paragraph 1 of Decision (D.) 83-09-054, this Commission ordered that "Standard Offer No. 4, Payment Options Nos. 1 through 3, as proposed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) shall be used by those utilities until further order of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order." With respect to Payment Options Nos. 2 and 3, the utilities were to exercise these options for a maximum period of one year after the effective date of the order. Because D.83-09-054 became

effective on September 7, 1983, these payment options are due to expire on September 7, 1984.

Standard Offer No. 4 was the result of a negotiating conference held during the summer of 1983. The goal of the negotiating conference was to develop an interim Standard Offer No. 4 which the parties "could comfortably tolerate and work under while refinement and 'perfection' could be pursued in subsequent evidentiary hearings." (D.83-09-054, at p. 8.)

By Administrative Law Judge's (ALJ) Rulings issued during 1984, the procedure to be followed in these "subsequent evidentiary hearings" was established. The proceeding has been divided into two phases—Phase I which will focus on the appropriate costing methodology for Standard Offer No. 4 and Phase II which will examine the prices based on the adopted methodology, appropriate price approaches, and all other terms of Standard Offer No. 4. Hearings for Phase I began on July 23, 1984.

On May 7, 1984, the Commission staff filed a "Recommendation of the Commission Staff to Establish Procedures for Phase I of the Long-Run Offer Hearings." Among other things, the staff observed that because Phase I was limited to an examination of costing methodologies, it would be appropriate to defer issues related to payment options until Phase II as directed by the ALJ. Under these circumstances, it is the staff's opinion that energy Payment Options Nos. 1, 2, and 3 and the energy price forecasts adopted in D.83-09-054 be extended until the conclusion of Phase II. The staff asserts that this approach will preserve the status quo, enabling qualifying facilities (QFs) to have the benefit of energy price certainty and eliminating any need to analyze and adopt incremental energy rates prior to Phase II.

During the prehearing conference of May 9, 1984, the staff reiterated these recommendations. While there were no objections to the recommendations, at least one party requested that the incremental energy rate to be paid the QF by PG&E under Option No. 3 be based on the incremental energy rate approved in PG&E's most recent general rate case.

On June 15, 1984, Independent energy Producers (IEP) filed a motion for a revised procedural schedule for the Standard Offer

No. 4 proceeding. Specifically, IEP requests that (1) interim Standard Offer No. 4, Payment Options 1, 2, and 3 be continued through the end of 1986 or until the issuance of a final decision in this proceeding; (2) hearings on the "costing methodology" be commenced as scheduled by the ALJ; (3) hearings on a revised incremental energy rate be commenced no later than October 1984; and (4) hearings "on the broader assumptions and terms of a final Standard Offer No. 4" be commenced after the Commission issues its decisions on costing methodology and an interim incremental energy rate pricing option. According to IEP, the incremental energy rate used for purposes of interim Standard Offer No. 4 is not a viable option for gas-cogenerated QFs.

IEP's motion is supported by the Independent Power Corporation (IPC). IPC further asks that PG&E's SDG&E's and SCE's interim Standard Offer No. 4 incremental energy rates be modified to reflect information developed in their most recent general rate cases.

WE have reviewed these comments and concur with the staff, IEP, and IPC regarding the extension of negotiated Standard Offer No. 4. At the time we issued D.83-09-054 we contemplated that the issues related to the payment options would have been explored in evidentiary hearings prior to the expiration date set for Payment Options Nos. 2 and 3. In fact, we optimistically forecast the conclusion of these hearings as early as six months from the issuance of D.83-09-054. Unfortunately, only hearings on Phase I of this proceeding will be concluded prior to September of this year, with Phase II commencing after that time.

Under these circumstances, and given the general acceptance of interim Standard Offer No. 4, we will extend the effective date of the terms of that offer, including Payment Options Nos. 1, 2, and 3, and the energy price forecasts adopted in D.83-09-054. This extension, which applies to all terms of the offer, will be effective until further order of this Commission.

We will not, however, amend Payment Option No. 3 in any way. That payment option was part of the negotiated package which the Commission approved on D.83-09-054. A change in one term would require the reexamination of all other terms of the

standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the evidentiary hearings now scheduled in this proceeding. We also note that a QF who finds the terms of interim Standard Offer No. 4 unacceptable may in fact negotiate a separate contract. Despite some QFs dissatisfaction with that remedy, we have made clear in previous decisions that all utilities are to negotiate with QFs in good faith.

With respect to the requests for October hearings on the utilities' incremental energy rates, we are unable to commit our limited resources to such hearing dates at this time. At the most, we can reiterate that hearings on Phase I began on July 23, 1984. Upon completion of that phase, the Commission will make a determination either in its decision in Phase I or by ALJ Ruling whether to segregate the issue of incremental energy rate valuation and hear the matter prior to Phase II hearings.

Findings of Fact

1. A reasonable modification of D.83-09-054 has been requested by the Commission staff, IEP, and IPC to extend the effective date of interim Standard Offer No. 4.

2. The other requested modifications of the Standard Offer No. 4 procedural schedule cannot be adopted at this time.

Conclusions of Law

1. The terms of interim Standard Offer No. 4 approved in D.83-09-054 should be extended until further order of this Commission.

2. The motion of IEP should be denied, except to the extent granted in keeping with Conclusion of Law 1.

3. To ensure the extension of Standard Offer No. 4 before it would otherwise expire, this order should be made effective today.

ORDER

IT IS ORDERED that:

1. All terms and conditions of interim Standard Offer No. 4 adopted in D.83-09-054 shall be extended until further order of this Commission.

2. The motion of Independent Energy Producers, except to the extent granted by Ordering Paragraph 1, is denied.

This order is effective today.

Dated August 1, 1984, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

Commissioner William T. Bagley, being necessarily absent, did not participate.

APPENDIX E

Decision 85-04-075 April 17, 1985

Before the Public Utilities Commission of the State of California

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983 and August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, and August 10, 1983)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983 and August 2, 1983

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Ins ituting Rulemaking No. 2

And Related Matters.

INTERIM OPINION

I. Summary

This decision continues the suspension of Payment Option No. 3 of interim Standard Offer (SO) 4 for Qualifying Facility (QF) projects over 50 megawatts (MW), which had been ordered earlier for Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE). It also extends the suspension for projects over 50 MW to Payment Option No. 3 of interim SO 4 for San Diego Gas and Electric Company (SDG&E). It presents two options for comment regarding continued availability and terms of all of Payment Option No. 1 and Payment Option No. 2, and of Payment Option No. 3 for projects less than 50 MW, prior to availability of a final long-run standard offer.

In assessing whether the existing standard offers continue to provide a reasonable protection for ratepayers, we have relied primarily on the utility filings of the results of project information questionnaires sent to QFs as part of our adopted Interconnection Priority Procedure (IPP), and on the information contained in

the utilities' most recent Quarterly Status Reports (QSRs) containing data current through the end of 1984. We conclude that the capacity payments in the interim SO 4 and the energy payments in Payment Option No. 1 and Payment Option No. 2 of the interim SO 4 would over-value additional QF projects not already under contract to the utilities. This is true for all sizes of QF projects and for SDG&E as well as for PG&E and SCE.

The Public Staff has recommended an immediate suspension of all payment options of interim SO 4 for PG&E and SCE until a final SO 4 is available, unless prices are adjusted to reflect current conditions. We agree with Public Staff that further study is needed of the implications of large cogeneration projects over 50 MW for utility resource planning purposes. Because of the potentially large impact of such projects on system avoided costs, we prefer that they not be allowed to sign Payment Option No. 3 until we understand more fully the utilities' long-run costs avoided by such projects as part of Phase II of the current long-run pricing proceeding.

Such caution does not appear warranted for other projects, however. Because of our continued wish to encourage cost-effective QF development, and because of the continued uncertainty regarding how many signed QFs will actually complete their projects and operate successfully, we are reluctant to suspend interim SO 4 entirely. At the same time, because of our desire to not delay further the development of a final SO 4, we see only one other realistic approach to providing for the protection of ratepayers at this time: that is for us to modify the interim SO 4 prices offered to new QFs which have not yet signed contracts to a level which reflects the value of additional QF projects more realistically. This action would maintain the availability of interim SO 4 contracts for most projects while final SO 4 terms are being developed, yet not unduly delay the final SO 4 proceedings.

With this in mind we present a method for adjusting the capacity payments in PG&E's and SCE's interim SO 4 contracts, based on calculations provided by our staff at the request of the assigned Commissioner, and detailed in Appendix A. The capacity payments in SDG&E's interim SO 4 would be modified to those adopted for its SO 1 and SO 2 in its most recent general

rate case. We also propose that the energy payments in payment Option No. 1 and Payment Option No. 2 be reduced by 10 percent, but conclude that no adjustment to the incremental energy rates in Payment Option No. 3 for projects under 50 MW is warranted at this time.

The revised interim SO 4 contracts would be in effect for each utility only until a set amount of new QF capacity enters into contracts, standard or non-standard, with the utility. That amount is 1,250 MW for each of PG&E and SCE and 200 MW for SDG&E, counted from April 17, 1985. At that point, all of interim SO 4 would be suspended for that utility until a final long-run standard offer becomes available. Projects signing revised interim SO 4 contracts would have to comply with the milestones adopted in our Interconnection Priority Procedure.

We provide for a workshop on May 3, 1985, in which staff will be available to answer any questions parties may have regarding the calculations underlying the capacity adjustment, and for parties to file written comments by May 10, 1985, stating whether they prefer complete suspension of interim SO 4 or implementation of the capacity and energy payments presented in this decision. Based on the filed comments, we plan to choose between the two approaches by June 5, 1985.

To prevent a "gold rush" of projects wanting to sign the current interim SO 4, we suspend all payment options of interim SO 4, effective immediately, pending further Commission action.

II. Background

We first authorized what is termed interim Standard Offer 4 in September 1983, by Decision (D.) 83-09-054. The three payment options under SO 4 resulted from a negotiating conference among the parties, held at our direction. A final SO 4 based on the utilities' long run avoided costs is being developed through evidentiary hearings. However, there was substantial agtreement among utilities, QFs, and our staff that such an interim solution should be in effect until the final SO 4 becomes available. Briefly, the three payment options are as follows:

Payment Option No. 1 provides increasing energy payments which are set for the first 10 years of the contract at the time the contract is signed. Oil or gas-fired cogenerators are allowed to receive only 20 percent of their energy payments under Option 1.

Payment Option No. 2 provides fixed, levelized energy payments based on Option 1 forecasts of energy prices, for the first 10 years of the contract. Since energy payments in the early years are larger than their value to the utility, QFs must post security and must pay damages if they do not perform for the duration of the levelization period. Oil or gas-fired cogenerators cannot sign Option 2 contracts.

Payment Option No. 3 provides "incremental energy rates" which are fixed at the time the contract is signed, for up to 10 years. The QF receives energy payments which are the incremental energy rates times the gas (or oil, if it is the marginal fuel) price at which the utility buys fuel for its own generation facilities. For PG&E, the QF can select a band width around the forecast incremental energy rates, and will receive payments based on the floor or ceiling of the band width if PG&E's realized incremental energy rates are outside the band width.

For any of the three payment options, QFs may elect to deliver either firm or as-delivered capacity, with capacity payments equal to those in effect for SO 1 or SO 2 at the time of the negotiating conference, for as-available or firm capacity respectively.

While all the parties participating in the negotiating conference were in general agreement regarding the reasonableness of Payment Option No. 1 and Payment Option No. 2, the issue of the utilities' forecast of incremental energy rates was not resolved at the negotiating conference to the satisfaction of some QFs. QFs indicated that they found SCE's filed Payment Option No. 3 acceptable while PG&E's and SDG&E's were not, and requested that the negotiating conference be reopened to pursue what, form their perspective, would be a "better" forecast from PG&E and SDG&E.

In D.83-09-054 we declined to reopen the negotiating conference, and approved the terms of Payment Option No. 3 as filed by PG&E andSDG&E, "on the positive assumption that some QFs may find it useful pending a complete review of Standard Offer #4 and all payment options during evidentiary hearings, during which the feasibility of further negotiations is always an option." (D.83-09-054, p. 46.)

In D.83-09-054, The Commission specified that Payment Option No. 1 would be in effect for at most two years, and that Payment Option No. 2 and Payment Option No. 3 would be available for only one year, due to reservations about whether longer provision of these options would be in the public interest. Our intent at that time was that a final SO 4 would be approved by the set expiration dates. When this proved overly optimistic, we extended by D.84-08-035 all three payment options of interim SO 4 until further order.

D.84-08-035 also addressed a motion for a revised procedural schedule for the SO 4 proceeding which had been filed by the Independent Energy Producers Association (IEP) and supported by the Independent Power Corporation (IPC). These two parties requested that hearings on a revised incremental energy rate for use in Payment Option No. 3 of Interim SO 4 be commenced no later than October 1984. According to IEP, the incremental energy rate in interim SO 4 is not a viable option for gas-fired cogeneration projects. In D.84-08-035 we denied IEP and IPC's request; stating that:

> "A change in one term would require the reexamination of all other terms of the standard.
>
> "A change in one term would require the reexamination of all other terms of the standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the evidentiary hearings now scheduled in this proceeding.

. . .

> "Upon completion of [Phase I of the hearings on a final SO 4], the Commission will make a determination either in its decision in Phase I or by ALJ Ruling whether to segregate the issue of incremental energy rate valuation and hear the matter prior to Phase II hearings." (D.84-08-35, p. 4.)

In April 1984, the Commission issued an Order Instituting Investigation (I.) 84-04-077 into the transmission system operations of the major electric utilities, in response to alleged transmission constraints on PG&E's transmission system which might restrict the development of QFs in the northern portion of PG&E's service territory.

On October 17, 1984, the Commission issued D.84-10-098, which suspended Payment Option No. 3 of SO 4 for PG&E for QF projects over 50 MW, in response to reports from our Public Staff and PG&E that a number of large oil and gas cogenerators had signed or were anticipated to sign this offer. While we had not imposed a MW limitation on the quantity of QFs which could sign Payment Option No. 3, we had earlier recognized potential problems:

> "We recognize the benefits of having oil and gas cogenerators on the system to displace the units, but only to the extent that: 1) cogeneration results in a more efficient use of fossil fuels (i.e., the cogenerator's actual incremental energy rate is lower than the utility's) and, 2) California's resource base, no matter how well it can be diversified, may require some oil and gas generation units to meet demand. We are concerned, however, that this energy payment option could, over time, provide incentives to oil and gas cogenerators that are not commensurate with the benefits described above." (D.83-09-054, pp. 44, 45.)

We ordered additional filings assessing how much of the capacity signed under SO 4 with PG&E is likely to actually come on line and how much additional capacity, particularly large cogeneration projects, could be expected to sign contracts within a year. We also set an en banc hearing for November 5, 1985 to receive comments from PG&E, the Public Staff, and other

interested parties regarding the suspension of Payment Option 3. We stated that:

> "We intend to make any adjustments to Payment Option #3 as soon as possible so that any uncertainties aroused by today's actions will be short-lived. Therefore, this suspension order will automatically expire on December 5, 1984 unless the Commission issues an order outlining specific steps for further action on this issue on or before that date." (D.84-10-098, p. 4.)

At the en banc hearings and through written comments as well, parties were asked to respond to a motion of the Public Staff to expand the suspension to include SO 2 and the remainder of SO 4, for projects over 50 MW. PG&E requested an even broader suspension, of all of interim SO 4 and all of SO 2 for projects over 10 MW.

On December 5, 1984, the Commission issued a decision extending the suspension to January 16, 1985, stating that:

> "[W]e conclude that the cornerstone for determining the extent of QF capacity in PG&E's service territory is the adoption of a milestone procedure to mark the progress and commitment of each QF project. It is clear that such steps have not yet been taken by PG&E. Further, without such a procedure it is difficult for this Commission or any other party to verify the exact extent of the impact of QF development on PG&E's resource plan and its ratepayers.
>
> "[W]e find that it is reasonable to continue the suspension of Payment Option #3 of PG&E's interim Standard Offer 4, but coordinate any further expansion or removal of that suspension with the milestone procedure to be considered in I.84-04-077. We believe that a sufficient basis to maintain the status quo has been presented by PG&E. We find, however, that no further action is warranted until we have had the opportunity to consider the comments and milestone proposals to be presented during the public hearing scheduled for December 17, 1984 in I. 84-04-077." (D. 84-12-027, pp. 2, 3.)

In response to the Commission directive, a committee of representatives from the Public Staff, the utilities, and QFs prepared a milestone procedure designed as an interconnection priority procedure (IPP), and presented it at the December 17 public hearing. On January 16, 1985, we adopted a slightly modified version of the proposed IPP in D.85-01-038.

One of the modifications we required in the IPP was a new requirement that PG&E, SCE, and SDG&E compile basic project definition information on all QFs in their territories, through mailing a questionnaire if needed, and that they file summaries of the results by March 18, 1985. They have made the compliance filings, and also supplemental filings providing more detail as requested by the assigned Commissioner.

Also on January 16, we again extended the suspension of Payment Option No. 3 of SO 4 for PG&E for QF projects over 50 MW. The Public Staff had recommended in a motion filed on January 4, 1986 that the suspension be extended until "either (a) 18 months plus a 20-day notice period from the date the Interconnection Priority Procedure is adopted, or (b) the issuance of a final decision on long-run avoided cost pricing [in this proceeding]." (Pulbic Staff Motion, p. 10) In D.85-01-040, we concluded that:

> "We do not think that QF development is served by placing the larger QFs 'on hold' for 18 months. Rather, we believe that is our responsibility to maintain a continuing review of QF development in PG&E's service territory, especially in light of the absence of any examination of estimates in an evidentiary proceeding open to all interested parties." (D.85-01-040, p. 3)

Instead, we continued the suspension only until April 17, 1985, to give us time to review the utility filings in compliance with the adopted IPP.

On January 31, 1985, SCE filed a motion (SCE Motion) seeking an emergency ex parte order providing a suspension of Payment Option No. 3 of SO 4 in its territory comparable to that in place for PG&E. Public Staff filed a response in support of SCE's motion and renewing its arguments in support of its

October 29, 1984 recommendation to suspend all payment options under interim SO 4 until adoption of a final SO 4. We concluded, in D.85-02-069, that SCE is at some risk of having QF energy supplies exceed its needs, and that it was reasonable to grant the requested suspension until April 17, 1985. We stated that, upon receipt of the IPP filings, we would review the available information to determine the accuracy and verifiability of the current estimates of QF development in both PG&E's and SCE's service areas.

III. Discussion

The lengthy compilation of occurrences and Commission decisions reiterated above shows the rather tortuous path leading to today's decision. As discussed below, we still do not have sufficient information to feel absolutely confident that we have a good grasp of likely QF development in California. However, much more information is available now than at the time of our initial actions last fall.

Questions which must be examined include:

1. How much of the signed QF capacity in each utility's service area is likely to come on-line and what is its likely impact on system reliability?

2. Should the partial suspension of interim SO 4 lapse?

3. What would be the effects if interim SO 4 were suspended until a final SO 4 is available?

4. Would a second negotiating conference be successful?

5. Are the capacity payments in SO 4 reasonable?

6. Are the energy prices in Payment Option No. 1 and Payment Option No. 2 of SO 4 reasonable?

7. Are the incremental energy rates in Payment Option No. 3 of SO 4 reasonable?

We will address each of these issues in turn.

Viability and Effect of QF Projects with Signed Contracts

SCE asserts that it already has under contract 95 percent of the QF capacity which it will need through 1994 (SCE Motion, p. 2). PG&E claims that the capacity prices being offered in SO 4 are substantially too high, mainly because of the unexpectedly large number of QF contracts it has signed since the prices were established.

Determination of the accuracy of PG&E's and SCE's assertions is critical to our decision regarding whether to extend or expand the existing suspension of a portion of interim SO 4. In this section we examine the information available to us to assess whether it supports PG&E's and SCE's positions. We also look at comparable information for SDG&E, to determine whether action regarding its interim SO 4 might also be warranted.

Table 1, Table 2, and Table 3 show, for PG&E, SCE, and SDG&E respectively, the amounts of capacity which were operational, under contract, and under active discussion at the end of 1984 according to the Quarterly Status Reports which the utilities file regularly with the Commission.[1]

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[1] Quarterly Status Reports are required filings by prior order of this Commission. For the purposes of this order, we take notice of the Quarterly Status Reports filed for December 31, 1984.

TABLE I

Qualifying Facility Projects
Pacific Gas and Electric Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	124	207	118–199
25–49.9 MW	148	656	473
50 MW or larger	75	890	2804
Solid Waste/Biomass:			
Cogeneration	87	411	24
Non Cogeneration	43	716	376
Geothermal	80	93	2
Solar	6	31	1
Wind	271	2024	287
Hydro	107	624	272
Other	1	0	0
TOTAL	942	5651	4462–4542
TOTAL EFFECTIVE CAPACITY	641	3534	3800–3877

(1) Fueled by other than solid waste/biomass.

TABLE 2

Qualifying Facility Projects
Southern California Edison Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	159	3	105
25–49.9 MW	75	172	175
50 MW or larger	55	1486	420
Solid Waste/Biomass	35	459	272
Geothermal	15	411	85
Solar	15	107	36
Wind	222	788	1327
Hydro	72	36	53
TOTAL	648	3463	2474
TOTAL EFFECTIVE CAPACITY	413	2418	1214

(1) Fueled by other than solid waste/biomass.

TABLE 3

Qualifying Facility Projects
San Diego Gas and Electric Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	66	0	54
25–49.9 MW	0	0	29
50 MW or larger	0	0	0
Solid Waste/Biomass	0	47	75
Geothermal	0	0	0
Solar	5	2	17
Wind	3	0	4
Hydro	2	0	8
TOTAL	76	49	188
TOTAL EFFECTIVE CAPACITY	62	42	154

(1) Fueled by other than solid waste/biomass.

PG&E has almost 2,200 MW more QF capacity under contract but not yet operational than does SCE (5,651 MW compared to 3,463 MW). However, over 80 percent of this difference is attributable to the larger amounts of wind and hydro capacity which PG&E has under contract. Because of the expected lower capacity factors during peak periods of as-available capacity, the nameplate capacities of such projects must be discounted significantly for system planning purposes. PG&E has only about 1,100 MW more "effective" capacity (as defined in Appendix A) under contract than does SCE. Because of the importance of considering effective capacity rather than nameplate capacity, we present much of the analysis in this section in terms of effective capacity.

As made clear by Table 3, QF activity is much less pronounced in SDG&E's area than for the other two utilities. SDG&E has projects totalling only about 42 MW of effective capacity under contract but not yet operational, and only about 150 MW of effective capacity under discussion.

As mentioned above, the utilities have also filed information regarding the status of non-operational QF projects which responded to the questionnaires mailed at our direction. Responses to some of the more pertinent questions by QFs which have signed contracts are summarized in Table 4. For PG&E, information is also presented for those projects not on transmission waiting lists in the northern portion of PG&E's territory or in the Altamont Pass area. This is important because many of the projects on the two waiting lists may proceed only if other projects with transmission priority do not go forward or PG&E builds the necessary transmission upgrades.

TABLE 4

Comparison of Responses
To Project Questionnaire
Of Projects with Signed Contracts
(Percent of Effective Capacity Responding)

	PG&E		SCE	SDG&E
	All	Not on Waiting Lists		
1. Critical Path Permits Applied for ..	47%	47%	66%	100%
2. Critical Path Permits Received	30%	36%	35%	4%
3. All or Portion of Financing Secured	43%	39%	40%	100%
4. Generating Equipment Ordered	17%	14%	26%	0%
5. Project Construction Begun	16%	20%	19%	0%
No. of Responses	206	125	61	5
Effective MW of Responses.....	2,091	1,436	1,895	8
No. of Signed Contracts (12-31-84)	308		115	10
Effective MW of Signed Contracts (12-31-84)	3,534		2,418	42

As can be seen, there was significant variation in the response rates to the questionnaires. SCE had a much larger response rate in terms of effective capacity under contract (78 percent) than did either PG&E (59 percent) or SDG&E (19 percent). This disappointing response reduces the credibility of the results. It is not clear whether those QFs which responded are representative of the other QFs.

We have hoped that the survey results would shed some light on the commonly held belief that projects signed by SCE are more likely to come on line than those signed by PG&E. If the responses can be viewed as reasonably representative of all QFs, then Table 4 supports this thesis, but only weakly. While a larger percentage of projects in SCE's area have applied for their critical path permits, about the same percentage of projects which responded to the questionnaires have received their permits in the two areas. Similary, while a larger percentage of projects in SCE's area say that they have ordered their generating equipment, about the same percentage in both areas are under construction.

Another measure of whether PG&E's signed capacity should be viewed as seriously as SCE's is the number of earlier contracts which have been cancelled. PG&E's December 31, 1984 Quarterly Status Report reveals that 21 signed projects with a total effective capacity of about 100 MW have "terminated." At the assigned Commissioner's request, SCE has informed us (see letter attached as Appendix B) that 5 signed projects have cancelled their contracts with SCE. Their total effective capacity is about 137 MW. PG&E's failed projects include 13 very small wind, hydro, or photovoltaic QFs totalling about 50 kilowatts in effective capacity, whereas the cancellation reported by SCE include only two projects under 1 MW. Excluding the very small projects, we conclude that the record of cancelled contracts indicates, if anything, that PG&E has been the more successful of the two utilities.

At the request of the assigned Commissioner, our staff has provided calculations of the effect of the existing signed QF capacity on the reserve margins and on the value of additional QF capacity for PG&E and SCE.[2] Those calculations, which are presented in detail in Appendix A, indicate that PG&E is likely to have much larger reserve margins through the late 1980s and early 1990s than SCE.

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[2] While these calculations were performed by members of the Public Staff Division (PSD), the results and the use we make of them do not in any way represent the position of the PSD. The provision of these calculations at the request of the assigned Commissioner does not prejudice PSD's position as an independent party in these proceedings.

In this analysis, PG&E's and SCE's nameplate signed capacity is translated into effective available peak capacity. Three scenarios are then created, representing development of 80 percent, 50 percent, and 30 percent, respectively, of the effective QF capacity under contract but not yet operational.

We realize that the probability that only 30 percent of QFs under contract will materialize is fairly low. We prefer to view the three scenarios as three versions of potential need for additional QF capacity. Thus, the 30 percent scenario would present a greater need for additional QF capacity, which could occur if, in addition to QF development being low, demand growth is higher than projected or utility plants such as Diablo, Helms, or San Onofre operate at low capacity factors.[3] The 80 percent scenario reflects lower need for additional QF capacity, which could occur if most of the signed projects come on-line, if demand growth is low, and/or if utility plants operate better than expected.

PG&E's and SCE's reserve margins through 1995 under the 80 percent and 30 percent scenarios are shown in Figure 1. The difference is striking. Under even the scenario of development of 30 percent of signed contracts (or the equivalent effect on reserve margins due to factors such as higher load growth), PG&E's reserve margin remains above 27 percent through 1992, though it falls to 18 percent by 1995. If the 80 percent scenario occurs, PG&E's reserve margin could peak at 49 percent in 1989 and still be 27 percent in 1995. By contrast, even if 80 percent of SCE's signed QF contracts produce operating projects, its reserve margin would reach a high of only 26 percent in 1988, dropping to 13 percent by 1995. Under the more pessimistic scenario of 30 percent QF development, SCE's reserve margin would remain at about 20 percent through 1988, but then falling rapidly to critical levels, reaching less than 17 percent by 1995.

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[3] For example, the need for additional QF capacity under the 30 percent scenario for PG&E corresponds roughly to development of 80 percent of signed QF capacity coupled with annual load growth through 1992 of 3.2 percent (rather than the 1.4 percent assumed in the calculations shown in Appendix A).

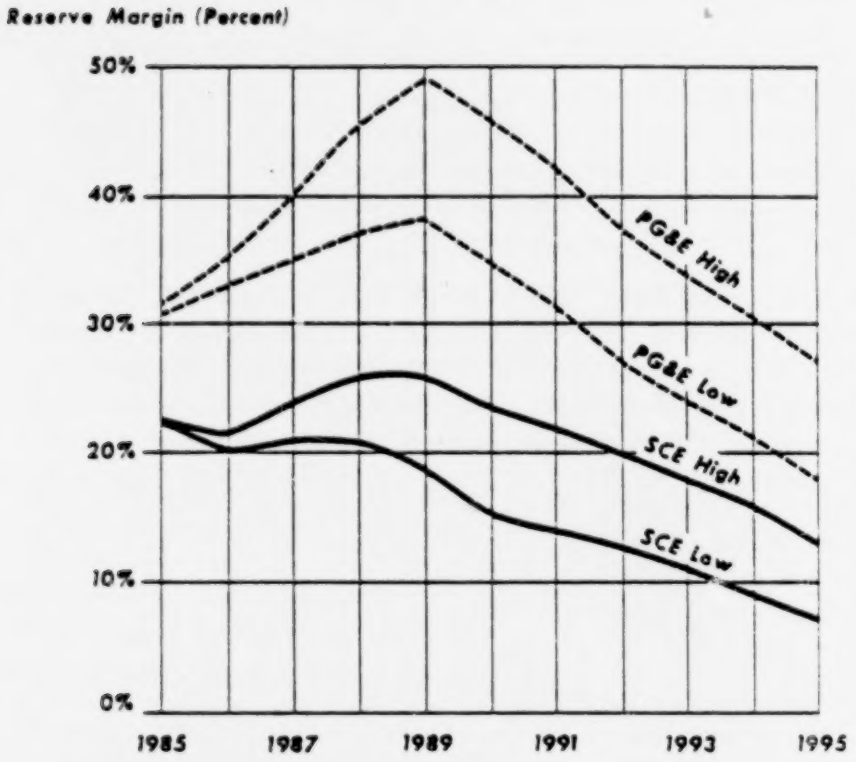

Figure 1 PG&E and SCE Reserve Margins with High and Low Levels of QF Development

We recognize that this analysis is somewhat simplistic. However, it does provide useful insight into the situation at hand. It appears fairly unlikely that PG&E will fall seriously short of capacity through the next decade even though additional QF capacity could enhance system reliability somewhat. Given the uncertainty surrounding QF development and other factors such as load growth, we conclude that SCE is premature in asserting that it needs only 158 MW of additional QF capacity through 1994 (SCE Motion, Table 1).

Should the Partial Suspension of Interim Standard Offer 4 Lapse?

In establishing interim SO 4, we expected that it would be in effect for only a short while. Because of concerns we had about both the levelized energy price option (Payment Option No. 2)

and the incremental energy rate option (Payment Option No. 3), we initially made them effective for only one year. At the time we extended these options in August 1984, we still did not foresee any serious problems with the overall payment levels, and expected that the terms of interim SO 4 would remain in effect until a final SO 4 became available.

Since last August, rapid changes in the QF market have outstripped the pace of our regulatory process. We have already imposed partial suspensions of interim SO 4 for PG&E and, later, for SCE. Now we must decide whether the suspension should be allowed to lapse, or whether other action is needed.

While SCE and, to a lesser extent, PG&E still have some need for additional capacity, the reserve margins for each utility under even the worst case scenario examined are high enough to indicate that the capacity payments in interim SO 4 (which are those which were offered in SO 1 and SO 2 at the time of the negotiating conference) may now overvalue new QF capacity.

Comparable calculations were not made for SDG&E, because it has not asserted that too many QF projects are signing contracts to sell power to SDG&E. We are concerned, however, about whether its prices being offered under interim SO 4 are too high. Even if only a limited number of QF projects are developed in SDG&E's region, if the payments are too high then ratepayer indifference is no longer maintained.

In Application (A.)82-12-57, SDG&E's 1984 general rate case, SDG&E proposed reductions in the capacity payments available to QFs in its SO 1 and SO 2, based on its forecast of the probability of need for additional capacity. We adopted these adjustments in D.83-12-065 as reasonable. Since the capacity payments which had been in effect for SO 1 and SO 2 prior to D.83-12-065 were equal to the capacity payments which are still in interim SO 4, we conclude, based on D.83-12-065, that they are too high for interim SO 4 as well.

The capacity payments must not be looked at in isolation, however. In deciding whether the terms of a proffered contract are acceptable, a third party undoubtedly looks at energy and capacity payments as a package. We recognized in D.84-08-035,

in considering whether the incremental energy rates in Payment Option No. 3 should be modified, that a change in one term of an interim SO 4 contract would require the reexamination of other components as well. Thus, in an assessment of what changes, if any, are appropriate for the capacity payments in interim SO 4, the energy payment component must be considered as well.

It is obvious that significant changes have occurred in the energy markets since the negotiating conference was held in June 1983. Natural gas prices have stabilized and even fallen, and further reductions are quite possible. In Table 5, the incremental costs of natural gas to PG&E, Southern California Gas Company (SoCal), and SDG&E are shown. PG&E and SDG&E have experienced substantial price reductions in the last 20 months, and if the effects of inflation were removed, Table 5 would show that SoCal's incremental cost of gas has also decreased, in real terms. There are at least two other easily available comparisons which provide a measure of changes in the utilities' avoided energy prices: The rates which utilities pay for natural gas for use in their own generating units (Table 6) and the avoided costs prices paid to QFs operating with short-run standard offer contracts. (Table 7). Natural gas rates for electric generation have declined for all three utilities, from 2 percent to 17 percent. SCE's and SDG&E's short-run avoided cost energy payments have declined substantially, by 11 percent and 15 percent respectively. PG&E's energy payments have increased dramatically, due to higher incremental energy rates adopted in its December 1983 general rate case decision. However, as pointed out in Table 7 (see also Table 14), that rate case decision also authorized PG&E to reduce its short-run avoided cost energy payments about 20 percent after Diablo 1 and Diablo 2 become commercially operable. At current gas prices, these payments would be reduced to about 5.4 cents per kilowatt-hour, which is about 7 percent less than the June 1983 level.

TABLE 5

Incremental Costs of Gas
(Cents per therm)

	June 1983	April 1985	Change
PG&E	32.7	29.1	−11%
SoCal Gas	32.7	32.8	+0.3%
SDG&E	41.5	35.5	−14%

TABLE 6

Natural Gas Rates
For Electricity Generation
(Cents per therm)

	June 1983	April 1985	Change
PG&E	53.50	52.45	− 2%
SCE	46.33	45.44(1)	− 2%
SDG&E	55.00	46.99	−17%

(1) Weighted average of episode and non-episode day rates.

TABLE 7

Non-Time Differentiated
Avoided Cost Energy Payments
(cents per kilowatt-hour)

	June 1983	April 1985	Change
PG&E	5.8	7.2(1)	+24% (−7%)(1)
SCE	4.6	4.1	−11%
SDG&E	6.2	5.3	−15%

(1) PG&E's energy payment will be reduced by about 13 percent after Diablo 1 becomes commercially operable and an additional 8 percent after Diablo 2 becomes commercially operable. At current G-55 rates the energy payment would average 5.4 cents per kilowatt-hour after Diablo 1 and Diablo 2 become commercially operable.

While we do not know what energy price forecasts were relied upon by the parties to the negotiating conference, we suspect that they did not predict the current turn of events. Thus, the energy components of interim SO 4 may be overstated. The rapid rate at which PG&E and SCE have signed interim SO 4 contracts indicates that the overall pricing terms, including both capacity and energy provisions, may be seen as very favorable by QFs.

If significant amounts of additional QF projects are allowed to sign contracts with the prices currently offered, ratepayers may indeed, as PG&E, and SCE assert, be required to pay more for the capacity and electricity than is reasonable. Because of this possibility, we agree with PG&E, SCE, and our staff that some action must be taken to protect ratepayers. The partial suspension cannot merely be allowed to lapse.

Possible Effects of a Suspension of Interim Standard Offer 4

From our viewpoint, continuation and expansion of the current limited suspension of interim SO 4 might be the easiest regulatory response to the current situation. It would require a minimum of staff resources and minimal delay in the Phase II hearings on the long-run avoided cost methodology. Since the utilities appear to be in no imminent danger of capacity shortfalls, a complete suspension might protect ratepayers while the final long-run standard offer is being developed.

Public Staff has repeatedly supported action along these lines. On October 29, 1984, PSD requested that PG&E's suspension be expanded to include SO 2 and the remainder of SO 4, for projects over 50 MW. On January 4, 1985 PSD recommended that the suspension be extended about 19 months, to allow time to ascertain how much of the QF capacity now under contract will materialize. or until the issuance of a final decision on long-run avoided cost pricing. Most recently, in its response to SCE's motion requesting suspension of Payment Option No. 3 for projects over 50 MW in its territory, PSD recommended suspension of all payment options of interim SO 4 until a final SO 4 is adopted, unless prices are adjusted to reflected current conditions through another interim Commission order.

In informal discussions, a number of other parties have also seemed agreeable to this approach. Other parties, most notably QFs negotiating contracts with the utilities, do not support continuation or expansion of the suspension.

We see several potential problems with a significant expansion of the current suspension. First, despite any amount of reassurances which we could make to the contrary, it might be viewed by QFs and the financial community as a reduction in our commitment to the development of the QF industry. That view certainly would not be accurate.

Second, some QF projects which are under consideration and which may be in ratepayers' best interests in terms of meeting future energy needs may not be able to survive a lengthy suspension of the availability of standard offer contracts. We realize that many QFs could wait until a final SO 4 is approved, and others might successfully enter into negotiations of non-standard contracts with the utilities to allow their projects to proceed this year.

This brings us to another concern. One of the benefits of the standard offers is that they provide reasonable back-up alternatives to QFs who want, for whatever reason, to negotiate non-standard contracts. They provide a measure of the reasonableness of the utility's negotiations and an alternative if negotiations do not yield terms acceptable to both the QF and the utility. Suspending the standard offers would remove this safeguard.

Further, the very action of suspending the standard offers for a significant period of time could be viewed by the utilities as a signal that the Commission might look unfavorable upon non-standard contracts signed in the interim unless the contract terms are significantly below the present standard offers. This response would not be surprising, since we would essentially be concluding that the existing yardstick is no longer reasonable.

While expansion of the suspension has been presented as an easy solution which would not require staff time or delay development of the final long-run standard offer, it may not be so simple. We have already had to address requests from QFs to allow switching to the interim SO 4 offer. It is easy for us to imagine that other QFs would similarly ask for special consideration if the

offer were completely suspended. We would confront the Hobson's choice to either devote the staff resources needed to evaluate such requests, or allow absolutely no exceptions to the suspension.

It has been suggested that there may not be significant amounts of QF capacity which would want to sign contracts in the next year or so, in effect that the "gold rush" effect that appears to have occurred in recent months may have already resulted in the signing of contracts for almost all QF projects which were being considered by potential developers. The utilities' Quarterly Status Reports appear to refute this possibility. As summarized earlier in Table 1 and Table 2, PG&E is in active discussion with potential QF projects totalling over 4,500 MW; developers of projects totalling over 2,400 MW are discussing contracts with SCE.

Rather than expand the suspension, we could simply extend it for a lengthy time period, as suggested by PSD in its second motion filed January 4, 1985. We would have to look carefully at the prices available to QFs under the remaining portions of SO 4. Utility filings show that significant amounts of capacity are signing up under these options. Thus, ratepayers could still bear a significant financial burden due to projects which would sign under these other offers if they were left intact.

Would a Second Negotiating Conference Serve A Useful Purpose?

A second negotiating conference has been suggested by a number of parties as a potential approach to adjust the terms of interim SO 4 which would, as would a complete suspension of interim SO 4, involve only a limited amount of the parties' time and thus cause only a minimal slippage in the development of the final long-run standard offers.

The first negotiating conference took five weeks, plus advance preparation time by the parties and time summarizing the results for submission to the Commission. While it was clearly successful, we would not be prepared to embark upon another negotiating effort of this magnitude.

The scope of a second negotiating conference would have to be very carefully and narrowly defined, to allow quick resolution.

However, capacity prices, which were not addressed in the first negotiations, are a central issue now. Questions regarding how much of already-signed QF capacity will actually materialize, what utility load growth will be, what utility resources should be included in determining need for additional capacity, and how additional capacity should be valued are too broad and much too controversial to give us any confidence that quick resolution is at all possible through the negotiating approach.

Because of our desire to not delay further the development of the final long-run standard offers, we conclude that a second negotiating conference should not be held.

Adopted Changes to Interim Standard Offer 4

Since the present interim SO 4 is a negotiated offer, there was no evidentiary record and we were thus not able to make findings regarding its reasonableness when it was adopted in D.83-09-054. We accepted it because it was a negotiated offer agreeable to all parties.

The conventional avenues which would allow us to protect ratepayers in light of changed circumstances—continuation or expansion of the present partial suspension, establishment of a second negotiating session, or commencement of focused evidentiary hearings—all have problems which we have discussed. Of these, if we must choose among them, we prefer a complete suspension of all of interim SO 4 until a final long-run standard offer is available. We do not believe that it is in anyone's interest to create another procedure to solve a short-term problem which would delay Phase II of these proceedings

This places us in a quandry. We have searched for a solution less draconian than a complete suspension, so that the benefits of having standard offers in-place can be preserved while the Phase II hearings proceed. The only alternative which appears feasible is for us, using our best judgment, to present potential modifications of some of the terms of interim SO 4, to levels which would better protect ratepayers. We propose this unusual approach because it may be preferable to the complete suspension which otherwise appears necessary.

As detailed in the following sections, we present certain modifications to the prices in interim SO 4 for comment by the parties. While we try in this decision to fully explain their basis, a workshop will be held on May 3, 1985 to allow parties to request any further clarification which may be needed. Parties are expected to file comments by May 10, 1985 regarding whether they prefer adoption of these modifications or a complete suspension of interim SO 4 until a final long-run standard offer is available.

To prevent a "gold rush" of projects asking to sign the current interim SO 4, we suspend all payment options of interim SO 4, effective today. Based on the filed comments, we plan to decide whether to leave the suspension in place or to implement the price changes we have proposed by June 5, 1985.

We conclude that QFs which sign one of the revised interim SO 4 offers (if after filed comments we adopt the revisions) should have the option of switching to a final SO 4 contract when it becomes available. We believe that the two proposed modifications—a reduction in prices and the allowance of future contract switching—combine to provide both protection to ratepayers and assurance to QFs regarding the reasonableness of the modified interim SO 4.

As a further protection to ratepayers, we would allow the revised contract terms to be in effect for each utility only until a set amount of new QF capacity enters into contracts (standard or non-standard) with the utility. That amount is 1,250 MW for each of PG&E and SCE and 200 MW for SDG&E, counted from April 17, 1985. At that point, all of interim SO 4 would be suspended for the utility until a final long-run standard offer becomes available.

If a modified interim SO 4 is reinstated on June 5, 1985, it should contain a requirement that the QF meet all milestones in the adopted Interconnection Priority Procedure in order for the contract to remain in force. While the 1,250 MW limit (200 MW for SDG&E) would apply to all signed contracts, not just interim SO 4, we conclude that this requirement in interim SO 4 is needed to reduce any tendency there may be for would-be

developers without serious projects to sign contracts and possibly prevent other more viable projects from proceeding.

From the time that we approved the terms of interim SO 4 in D.83-09-054, we have expressed reservations about resource planning issues relating to oil and gas cogeneration. They will be addressed in Phase II of the evidentiary portion of these proceedings. These issues are critically important in light of the quantity of large cogeneration projects which are discussing contracts with the utilities at this time.

According to the utilities' Quarterly Status Reports (summarized in Table 1 and Table 2), PG&E and SCE are discussing contracts for large (over 50 MW) cogeneration projects whose capacities total over 3,200 MW. These projects alone would more than fill the 2,500 MW of additional QF capacity we would allow for these two utilities before suspension of the modified interim SO 4.

Because of questions we still have regarding the implications of large cogeneration projects on a utility's avoided costs, we conclude that such projects should not be allowed to sign interim SO 4 contracts until we can examine these issues in Phase II. Thus, we will continue the suspension of Payment Option No. 3 of interim SO 4 for projects over 50 MW until a final long-run standard offer is available. We also extend this suspension to SDG&E.

We continue to expect utilities to negotiate in good faith with large cogenerators based on current estimates of long-run avoided costs, but remind them that the reasonableness of such negotiated contracts will be reviewed carefully by this Commission.

Capacity Payments in Interim Standard Offer 4

As discussed earlier, the PSD, at the assigned Commissioner's request, provided calculations of the possible effects of existing signed QF capacity on the value of additional QF capacity for PG&E and SCE. The method and results are contained in Appendix A.

As described in Appendix A, additional capacity is valued based on utility reserve margins under each of three scenarios.

Additional capacity was assumed to have the full value of a gas turbine in any year in which the reserve margin without it would fall below 20 percent, and to have no value if the reserve margin without it would be greater than 35 percent. The assumed capacity value varies linearly between the value of a gas turbine and zero for reserve margins between 20 percent and 35 percent. For each scenario, staff provided a table of levelized prices for a 1,000 MW block of additional firm capacity.

In Table 8, we present some of the results for PG&E and SCE for the scenario of 80 percent QF development. For this scenario, application of the above formula indicates that the capacity value of a QF signing a 20-year contract for firm operation beginning in 1986 should be 35 percent of that in PG&E's current interim SO 4 if it signs with PG&E but 78 percent of that in SCE's interim SO 4 if it signs with SCE. This striking difference between the capacity value of additional capacity to the two utilities carries over to the other scenarios analyzed as well. Comparable results for the 30 percent QF development scenario still show capacity values to be only 50 percent of PG&E's current interim SO 4 capacity payment, but 93 percent of SCE's, for a QF committing to 20 years of firm operation beginning in 1986.

TABLE 8

Calculations of Capacity Payments For Additional 1000 MW Block QFs

Levelized $/kW-year (Percent of SO 4 Capacity Payment)

PG&E: Assuming 80% of Signed QFs Materialize

Year Operation Begins	Number of Years of Firm Delivery 1	10	20
1985	19(23)	4(4)	40(31)
1986	1(1)	4(4)	47(35)
1987	0(0)	10(8)	57(39)

SCE: Assuming 80% of Signed QFs Materialize

Year Operation Begins	Number of Years of Firm Delivery 1	10	20
1985	73(90)	79(73)	105(80)
1986	83(95)	84(72)	112(78)
1987	68(72)	89(70)	119(77)

Because of the large amounts of QF projects which have signed contracts with PG&E and SCE since interim SO 4 was negotiated, and because our analysis of the effects of such capacity indicates that the value of additional QF capacity to the utilities and ratepayers is significantly less than the capacity payments now in interim SO 4, we conclude that the capacity payments in PG&E and SCE's interim SO 4 should be adjusted if it continues to be available for new projects. Since large amounts of QF projects are still under discussion, we conclude further that updated capacity payments should be based on allowing 1,000 MW of additional capacity to enter into contracts (standard or non-standard) with the utility.

Because of the expectation, however, that not all projects which sign contracts will actually reach fruition, we would allow the revised capacity prices to remain in effect for each utility until new QF projects totalling 1,250 MW have come under contract with that utility, measured from April 17, 1985. If 80 percent of these projects materialize, this would result in 1,000 MW of on-line capacity. If that limit is reached for either PG&E or SCE, then all of interim SO 4 will be suspended for that utility until a final SO 4 becomes available.

The capacity tables calculated by staff consider the effect of only those QF projects which have signed contracts by December 31, 1984. Use of those results for pricing a 1,250 MW block of QF projects entering into contracts after April 17, 1985 would overvalue that capacity, since projects signed between January 1 and April 17, 1985 would not be considered.

We instruct PG&E and SCE to file in these proceedings by May 1, 1985 a statement listing all QF projects by size, technology, and contract type, which have entered into contracts between January 1, 1985 and April 17, 1985, or which have cancelled contracts during that period. If we choose to adopt modifications to capacity prices on June 5, 1985 we will ask staff to update the capacity tables commensurately.

As explained earlier, calculations were made for three scenarios of development of QF projects already under contract. If modifications are adopted on June 5, they will be the numeric average of

the calculated capacity values resulting from the three scenarios, updated to incorporate the results of PG&E's and SCE's May 1 filings. The complete tables of such capacity values based on contracts through December 31, 1984 are shown in Table 9 and Table 10, for illustration.

This capacity adjustment method is not an ideal solution to the difficult problem of establishing accurate capacity prices. We have wrestled with other adjustment mechanisms such as PG&E's Energy Reliability Index and staff's Reliability Adjustment Factor proposed recently in SCE's 1985 general rate case (A.83-12-53). Not being completely satisfied with either of these two mechanisms, we ordered both PG&E and SCE in conjunction with staff, to develop improved capacity adjustment mechanisms in subsequent proceedings based on an Expected Unserved Energy (EUE) reliability criteria. Future analyses of the EUE criteria and other measures of reliability should provide us with the opportunity to institute a more refined capacity adjustment mechanism. Lacking such analyses at this time, we would adopt capacity price adjustments for interim SO 4 based on a reserve margin reliability criterion as described above.

As discussed earlier, we found in D.83-12-065 that the same capacity prices now in SDG&E's interim SO 4 were too high for SO 1 and SO 2, and adopted modified capacity payments for SDG&E's SO 1 and SO 2. We propose that the modified capacity payments now in effect for SO 1 and SO 2 be incorporated into a revised interim SO 4 for SDG&E as well.

For SDG&E, we would require suspension of the modified interim SO 4 if new QF projects totalling 200 MW sign contracts with SDG&E before a final SO 4 becomes available. This is comparable, relative to their peak loads, to the 1,250 MW limit set for PG&E and SCE.

Energy Payments in Payment Option No. 1 and Payment Option No. 2 of Interim Standard Offer 4

We must also look at whether the energy payments in Payment Option No. 1 and Payment Option No. 2 of interim SO 4 should be adjusted. If they are too high, then adjusting only the capacity payments may not provide sufficient protection for ratepayers.

The annual average energy payments in Payment Option No. 1 and Payment Option No. 2 are shown in Table 11 and Table 12, respectively, for PG&E, SCE, and SDG&E. While we do not have access to the marginal fuel prices which formed the basis for negotiations in June 1983, other measures discussed earlier provide some basis for comparison.

The general trend since that time in incremental natural gas prices, prices for gas burned in utility plants, and short-run avoided energy payments is consistently downward, as chronicled earlier in Table 7, Table 8, and Table 9. A comparison of the energy prices for 1985 in the short-run SO 2 and the current SO 4 is also telling:

	SO 2 (¢/kWh)	SO 4 (¢/kWh)	SO 4/SO 2
PG&E:			
Now	7.2	5.55	0.77
After Diablo	5.4	5.55	1.03
SCE	4.1	5.70	1.39
SDG&E	5.3	6.40	1.21

TABLE 9

Pacific Gas and Electric
Firm Capacity Price Schedule
(Levelized $/kW-Year)
For the First 1000 MW of Additional QF Power

Average of Values from Scenarios 1, 2 and 3

Year Operation Begins	# Of years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	10	34	50	60	68
1986	6	1	13	41	57	68	76
1987	0	0	23	51	68	80	89
1988	0	0	36	65	83	95	104
1989	0	5	52	81	99	112	121
1990	0	17	70	99	118	132	141
1991	0	37	93	122	141	155	165

TABLE 10

Southern California Edison
Firm Capacity Price Schedule
(Levelized $/kW-Year)
For the First 1000 MW of Additional QF Power

Average of Values from Scenarios 1, 2 and 3

Year Operation Begins	# Of years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	77	92	105	115	123	129
1986	85	81	99	113	124	132	138
1987	80	84	105	120	132	141	148
1988	69	92	114	130	142	152	159
1989	77	105	128	144	157	167	174
1990	97	121	142	159	172	183	191
1991	111	135	155	173	187	198	207

TABLE 11

Payment Option No. 1

Forecasted Energy Price Schedule (Annual Average)
(¢/kWh)

Year	PG&E	SCE	SDG&E
1983	5.18	5.30	—
1984	5.47	5.60	5.90
1985	5.55	5.70	6.40
1986	5.79	6.00	6.40
1987	6.16	6.40	6.30
1988	6.70	6.90	6.70
1989	7.34	7.60	7.90
1990	7.84	8.10	8.60
1991	8.34	8.60	9.20
1992	9.01	9.30	10.00
1993	9.75	10.10	10.30
1994	10.54	10.90	11.10
1995	11.39	11.80	11.80
1996	12.24	12.60	12.60
1997	13.14	13.60	13.40
1998	—	—	14.20

1. Price calculated at primary generation level, with O&M expenses included, based on gas as the incremental fuel.

2. Price calculated includes line losses, O&M expenses, and is oil/gas based.

3. Price calculated at primary generation level, with O&M expenses included, and is oil/gas based.

TABLE 12

Payment Option No. 2

Levelized QF Energy Prices (Annual Average)
(¢/kWh)

Initial Year of Delivery	5-Year Levelization Forecast			10-Year Levelization Forecast		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
1983	5.57	5.7	—	6.27	6.5	—
1984	5.85	—	6.3	6.66	—	7.2
1986	6.62	—	7.0	7.61	—	8.1
1988	7.69	—	8.3	8.85	—	9.4

For SCE and SDG&E, interim SO 4 energy prices far outstrip those available under SO 2. Only PG&E offers higher short-run avoided-cost energy payments. After Diablo Canyon becomes commercially operable, its SO 2 prices are also expected to fall below the energy payment offered in interim SO 4.

Since, according to the incremental energy rate forecasts contained in Payment Option No. 3, the marginal efficiency of fuel usage is expected to increase somewhat during the next five years, we estimate that the streams of energy payments in Table 11 imply an underlying annual increase in oil or gas prices of about 7.3 percent (PG&E and SDG&E) to 7.5 percent (SCE).

We realize that the present oil and gas glut and the lull in inflation may not last throughout the forecast period, and a 7.5 percent escalation rate for natural gas may not be unreasonable in the future. But we certainly have not seen such price increases during the past 20 months, and the 1985 energy prices in interim SO 4 are clearly too high for SCE and SDG&E.

A final factor also indicates that the energy prices may be high for another reason. As Table 14 in the next section illustrates, the amount of resources on line can have a dramatic effect on marginal system efficiencies. Thus, we would expect that successful operation of an appreciable amount of the QF projects which have signed contracts since interim SO 4 was negotiated would have the effect of driving incremental energy rates lower than had been expected in June 1983. This would proportionally reduce the energy costs avoided by the utilities as a result of the next block of

QF projects signing up. If this were not reflected in the energy prices, then ratepayers would not receive this benefit of QF development.

We will not attempt to forecast energy prices at this time. However, all indications are that the payments in Payment Option No. 1 and Payment Option No. 2 are too high except perhaps the 1985 payments for PG&E. As an alternative to suspension of these payment options until proper energy forecasts can be examined through evidentiary hearings in Phase II, we propose an across-the-board reduction in these payments of 10 percent, except for the 1985 energy payments for PG&E. We ask for parties' comments by May 10, 1985, as discussed previously.

Incremental Energy Rates in Payment Option 3 of Interim Standard Offer 4

The incremental energy rates (IERs) which form the basis of Payment Option No. 3 must also be examined, and are set forth in Table 13. As noted above, IEP and IPC have asserted that the IERs in PG&E's Payment Option No. 3 are too low and need revision. According to IEP, PG&E's Payment Option No. 3 is not a viable option for small gas-fueled cogenerators.

We have three measures for assessing the IERs in PG&E's interim SO 4. First are the IERs shown in Table 14, which are those adopted in D.83-12-068 in PG&E's most recent general rate case. We determined at that time that reasonable IERs for PG&E after Helms and both Diablo Canyon nuclear units are operational range from 13,303 British thermal units per kilowatt-hour (Btu/kWh) to 8,489 Btu/kWh, depending on the time of day and season, with an annual average of 10,356 Btu/kWh. This is 14 percent higher than the IER of 9050 Btu/kWh for 1985 contained in PG&E's Payment Option No. 3.

TABLE 13

Payment Option No. 3

QF Incremental Energy Rates (Annual Average)
(Btu/kWh)

Year	Oil Based at Generation Level			Gas Based at Generation Level		
	PG&E*	SCE	SDG&E	PG&E*	SCE	SDG&E
1983	—	9400	—	—	9729	—
1984	8496	8930	9100	9000	9243	9519
1985	8543	8920	8600	9050	9232	8996
1986	8345	8870	7700	8840	9180	8054
1987	8354	8900	7700	8850	9212	8054
1988	8458	8900	7700	8960	9212	8045
1989	8326	9030	8200	8820	9346	8577
1990	8062	8880	8200	8540	9191	8577
1991	8062	8750	8200	8540	9056	8577
1992	8062	8750	8200	8540	9056	8577
1993	8062	8750	8200	8540	9056	8577
1994	8062	8750	8200	8540	9056	8577
1995	8062	8750	8200	8540	9056	8577
1996	8062	8750	8200	8540	9056	8577
1997	8062	8750	8200	8540	9056	8577
1998	—	—	8200	—	—	8577

* Curtailment Option A.

(1) O&M expenses included.

(2) O&M expenses not included.

TABLE 14

Pacific Gas and Electric Company
Adopted Incremental Energy Rates with
Various Major Resource Configurations*
Test Year 1984
(Btu/kWh)

Costing Period	Without Helms Without Diablo 1 Without Diablo 2	With Helms Without Diablo 1 Without Diablo 2	With Helms With Diablo 1 Without Diablo 2
Period A:			
On-Peak	13,674	14,086	12,168
Partial-Peak	12,665	13,382	11,369
Off-Peak	10,119	10,499	9,429
Seasonal Average	11,538	12,031	10,515
Period B:			
On-Peak	15,410	16,320	14,224
Partial-Peak	14,730	15,689	13,552
Off-Peak	11,353	11,625	10,261
Seasonal Average	13,089	13,692	11,954
Annual	12,427	12,982	11,340

Costing Period	With Helms With Diablo 1 With Diablo 2
Period A:	
On-Peak	10,692
Partial-Peak	9,923
Off-Peak	8,489
Seasonal Average	9,322
Period B:	
On-Peak	13,303
Partial-Peak	12,694
Off-Peak	9,468
Seasonal Average	11,122
Annual	10,356

* Based on weighted average hydro conditions; includes generation-level losses to the point of interconnection with the transmission grid.

Because the IERs in PG&E's Payment Option No. 3 are not time-differentiated, they do not convey a price incentive to cogenerators to schedule operations with emphasis on the time periods when electricity is of the most value to PG&E. We note, that, under SO 1, non-time differentiated capacity payments are half the average achievable if a QF accepts time-differenciated payments. While the value of energy does not vary as much with time and season as does capacity, we cannot conclude at this time that the difference between PG&E's Payment Option No. 3 and the IERs adopted in PG&E's general rate case is unreasonable.

Another useful measure is a comparison of the amount of non-biomass cogeneration which has signed contracts with PG&E and SCE since Payment Option No. 3 of interim SO 4 was negotiated and approved. In Table 15, this comparison is made. PG&E has signed over twice as many contracts for cogeneration projects less than 50 MW than has SCE, with over four times the total capacity. We recognize that this does not indicate directly whether the IERs in Payment Option No. 3 of PG&E's interim SO 4 are reasonably accurate. However, it is clear that they have not prevented many small gas-fired cogenerators from signing acceptable contracts with PG&E and proceeding with their projects.

TABLE 15

Capacity of Cogeneration Projects(1)
Which Signed Contracts
After September 1983

Megawatts (Number of Projects)

	Size of Project		
	0-25	25-50	Over 50
PG&E:			
Operational	72(17)	0	0
Non-Operational	151(29)	588(13)	831(9)
SCE:			
Operational	17(8)	0	0
Non-Operational	3(9)	172(6)	1,430(6)

(1) Fueled by other than solid waste/biomass.

Finally, as we discussed in the prior section, the unexpected number of QF projects which have signed contracts since the negotiating session in June 1983 would tend to drive down the IERs which are appropriate for future contracts.

Based on the information at hand, we cannot conclude that PG&E's IERs present an impediment to cogeneration development significant enough to warrant increases at this time, nor that the IERs offered by any of the utilities in interim SO 4 should be decreased to protect ratepayers.

PG&E's IERs will be addressed in 1985 and 1986 in two proceedings—the additional long-run proceedings and PG&E's 1987 general rate case. We hope that a more consistent approach will be developed between these two proceedings so that any adopted results will be directly comparable.

IV. Conclusion

We find ourselves in the unenviable position of reconciling, on scant information, two worthy but competing goals. First, there is our omnipresent duty to protect the interests of California electric ratepayers, ensuring that they receive reliable, safe utility service at the lowest reasonable rates. Then there is the more recent but also important goal of fostering the development of diverse, third-party electric generating resources, the QF industry. Our action is taken due to our concern that we may have, in pursuing the latter, neglected the first. This is an unfortunate development in that we fully expect QF development will ultimately benefit the electric ratepayer with improved system reliability, greater diversity of resources and rate stability. To ensure that both goals are pursued to what we hope will be a mutually compatible end, we today take pause to reevaluate one aspect of our QF program. Our hope is that all parties—utilities, QFs and their trade associations, our Staff and other intervenors—will participate in the course of action set forth in this order and help guide us to a positive, successful resolution of the concerns we here confront. While that resolution is as yet uncertain, we are confident that we are by today's order taking the best next step available to us to place QF development and integration on the right track.

Findings of Fact

1. The Commission has authorized utilities to execute contracts with Qualifying Facilities (QFs) based upon long-run avoided costs as reflected in long-term capacity and energy payments on the ground that such contracts served the public interest. These contracts are referred to as interim Standard Offer No. 4 (SO 4).

2. The terms and conditions of interim SO 4 were to be available to QFs pending the adoption of "final" SO 4 terms and conditions. The final SO 4 contract is being developed in an as yet ongoing proceeding.

3. Interim SO 4 offered three payment options to QFs. These options were to be available for a period of one year, except for Payment Option No. 1, which was to be in effect for up to two years.

4. By Decision 84-08-035, all payment options under interim SO 4 were extended until further order.

5. By Decision 84-10-098, the availability of Payment Option 3 of SO 4 was suspended as to projects greater than 50 megawatts for QFs seeking contracts with Pacific Gas & Electric Co. (PG&E) on the ground that an unexpectedly large response to this offer was being experienced, raising the danger that PG&E might be required to contract for capacity either that PG&E did not need or at a price in excess of its value to PG&E.

6. By Decision 84-12-027, the above suspension was continued to January 16, 1985, in order to coordinate further actions with an interconnection priority procedure.

7. By Decision 85-01-038, an interconnection priortiy procedure (IPP) was adopted; the IPP required, inter alia, that PG&E, Southern California Edison Co. (SCE) and San Diego Gas & Electric Co. (SDG&E) compile information of QF development activities in their service territories.

8. By Decision 85-01-040, the suspension of Payment Option No. 3 of interim SO 4 was again continued, this time through April 17, 1985, to provide time during which PG&E, SCE and

SDG&E could compile the information required by the IPP. Those utilities have done so and have filed their data and findings with the Commission.

9. By Decision 85-02-069, the availability of Payment Option No. 3 of SO 4 was suspended for SCE under terms similar to those applied in the case of PG&E; that suspension was imposed through April 17, 1985.

10. The December 31, 1984, Quarterly Status Reports filed by the utilities pursuant to prior Commission order show that PG&E, SCE and SDG&E have contracts with total nameplate capacity of 6593, 4111 and 125 megawatts, respectively. Additional projects could add 4542, 2474 and 188 megawatts, respectively, to those totals.

11. Under our asssumption of low QF development (the "30 percent scenario" shown in Appendix A, p. A-23), PG&E's reserve margin through 1989 is at least 31 percent.

12. Under our assumption of intermediate QF development (the "50 percent scenario" shown in Appendix A, p. A-11), SCE's reserve margin through 1989 is at least 20 percent.

13. There is a low probability that PG&E will experience unreasonably low reserve margins or capacity shortages through 1989. There is a higher, but still low, probability that SCE will experience capacity shortages over that same period; it is unlikely that, to avoid such shortages, SCE will need only 158 megawatts of additional QF capacity through 1994.

14. The low probabilities that PG&E and SCE will experience capacity shortages indicate that the capacity payments in interim SO 4 overestimate the value of new QF capacity to the utilities and their ratepayers.

15. Capacity payments made by SDG&E to QFs under Standard Offers Nos. 1 and 2 were reduced in Decision 83-12-065, the utility's last general rate case, in order to reflect SDG&E's forecasted need for additional QF capacity. Since the value of QF capacity under interim SO 4 was based upon those values as set forth in Standard Offers Nos. 1 and 2, the lower valuation for QF capacity under those standard offers would

indicate that a lower value should be used in its interim SO 4 as well.

16. Utility reserve margins provide a measure of the need a utility would have for additional generating capacity and, as a result, also provide a reasonable standard by which to measure the value of additional QF capacity.

17. As shown in Table 6, natural gas rates in California electric utilities have fallen since the time energy payments to QFs under interim SO 4 were adopted.

18. As shown in Table 5, real incremental natural gas prices to California distribution utilities have fallen since the time energy payments to QFs under interim SO 4 were adopted.

19. Energy payments to QFs under Payment Options Nos. 1 and 2 of interim SO 4 are based upon steam electric natural gas rates which were forecasted to increase.

20. The energy payments in Payment Options Nos. 1 and 2 of interim SO 4 overestimate the utility's avoided energy costs by assuming escalating marginal fuel prices.

21. A ten percent (10%) reduction in energy payments to QFs under Payment Options Nos. 1 and 2 of interim SO 4 reasonably reflects changes in the utilities' forecasted marginal fuel prices which have occurred since the Commission's adoption of interim SO 4.

22. Under the present terms of interim SO 4, there is a reasonable probability that the utilities and their ratepayers are paying too great a price for QF electricity.

23. A second negotiating conference would invest this proceeding with further delay and thereby would serve no useful purpose.

24. Assuming the Commission elects to make available a revised interim SO 4, permitting those QFs signing interim SO 4 under revised terms and conditions to switch to the terms and conditions of a final SO 4, when available, will provide some assurance to QFs that their interests will not be prejudiced by the revisions.

Conclusions of Law

1. It is reasonable to suspend the availability of interim SO 4 for QFs seeking to execute contracts with SCE, PG&E, and SDG&E until there is available an SO 4 contract with final terms and conditions. In lieu of a suspension for Payment Options Nos. 1 and 2 and Payment Option No. 3 for QF projects less than 50 megawatts, it would be reasonable to reduce: (1) the capacity payments offered under interim SO 4; and (2) the energy payments offered under Payment Options Nos. 1 and 2 of interim SO 4; and, to permit QFs to execute interim SO 4 contracts under these revised terms and conditions pending the availability of a final SO 4 contract.

2. Interested parties should be permitted to comment on whether suspending interim SO 4 or making available a revised interim SO 4, execpt for Payment Option No. 3 for projects over 50 megawatts, is the more desirable regulatory course of action pending the adoption of a final SO 4.

3. A second negotiating conference should not be held.

4. A workshop should be held to further explain to interested parties the manner and basis of the revisions to SO 4 proposed by the Commission.

5. Assuming the Commission elects to make available a revised interim SO 4, permitting those QFs signing interim SO 4 contracts under the revised terms and conditions to switch to the terms and conditions of a final SO 4, when available, is reasonable.

INTERIM ORDER

THEREFORE, IT IS ORDERED that:

1. Interim Standard Offer No. 4, as adopted by Decision 83-09-054, is hereby suspended for Southern California Edison Co., Pacific Gas & Electric Co. and San Diego Gas & Electric Co. With respect to projects proposed by Qualifying Facilities (QFs) under Payment Option No. 3 of interim Standard Offer No. 4 which are larger than 50 megawatts, the suspension shall be for an indefinite period. With respect to all other projects proposed by

QFS under interim Standard Offer No. 4, the suspension shall be effective until further order of the Commission.

2. Staff shall conduct a workshop on May 3, 1985, at which it shall explain and answer questions regarding the proposed revisions to energy payments under Payment Options Nos. 1 and 2 of interim Standard Offer No. 4 and capacity payments under all payment options of interim Standard Offer No. 4 as set forth in this decision.

3. Interested parties shall file written comments no later than May 10, 1985, stating their preference for the indefinite suspension of the entirety of interim Standard Offer No. 4 or the implementation of the subject revisions of energy and capacity payments under said Standard Offer.

This order is effective today.

Dated April 17, 1985, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

I abstain.
/s/ PRISCILLA C. GREW
Commissioner

APPENDIX A

CALCULATION OF VALUE OF ADDITIONAL QF CAPACITY

SOUTHERN CALIFORNIA EDISON
FIRM CAPACITY PRICE SCHEDULE
(LEVELIZED $/KW-YEAR)
FOR THE FIRST 1000 MW OF ADDITIONAL QF POWER

Scenario 1: Assume 50% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	73	77	94	107	117	125	131
1986	86	83	102	115	126	134	140
1987	81	88	108	123	134	143	150
1988	66	96	118	133	145	155	162
1989	80	112	132	148	160	170	178
1990	104	128	146	162	176	186	194
1991	122	140	159	176	190	201	210

Scenario 2: Assume 80% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	73	67	79	94	105	113	119
1986	83	65	84	100	112	121	127
1987	68	63	89	106	119	128	135
1988	51	68	98	116	130	139	147
1989	47	83	113	131	145	155	163
1990	69	104	131	149	163	174	182
1991	85	123	148	166	181	192	201

Scenario 3: Assume 30% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	87	102	114	123	131	137
1986	88	96	111	123	133	141	147
1987	90	102	118	131	142	151	158
1988	90	110	127	141	153	162	169
1989	103	121	138	153	165	175	183
1990	116	131	149	164	178	188	196
1991	125	141	159	176	190	201	210

Average Values from Scenarios 1, 2 and 3

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	77	92	105	115	123	129
1986	85	81	99	113	124	132	138
1987	80	84	105	120	132	141	148
1988	69	92	114	130	142	152	159
1989	77	105	128	144	157	167	174
1990	97	121	142	159	172	183	191
1991	111	135	155	173	187	198	207

WORK PAPERS

SOUTHERN CALIFORNIA EDISON COMPANY

General Assumptions

1. Peak-Availability of QFs

   a. All firm QFs will have 80% average peak availability.

   b. As-available QFs will have 20% average peak availability.

2. Time Distribution of QFs

   a. ⅓ of materializing QFs come on line 3 years after signing the contract.

   b. ⅔ of materializing QFs are on line 4 years after signing the contract.

   c. All materializing QFs are on line 5 years after signing the contract.

3. Value of Capacity

   a. Up to 20% reserve margin, QF capacity is worth full gas turbine with the utility.

   b. At over 35% reserve margin, the value of additional QF capacity is zero.

   c. Between 20-35% the value of QF capacity declines linearly from 1 to 0.

4. Capacity Cost

   a. Combustion turbine cost, inflation rate and discount rate same as adopted in the utility's last general rate case.

SOUTHERN CALIFORNIA EDISON COMPANY

QF Capacity Signed as of 12-31-84(a)

CALCULATION OF EFFECTIVE CAPACITY

	(MW)
Total QF Capacity Signed (Nameplate)	=4110
Total Effective QF Capacity	
Already Operational QFs (Nameplate)	= 647
Out of it, wind + small hydro (Nameplate)	= 293
Other	= 354
Total effective operational QF capacity = (293 × .2) + 354	= 413
Not yet on line = 2831 − 413	=2418
Total committed effective capacity:	
If all QFs come on line = 413 + 2418	=2831
If 80% QFs come on line = 413 + (.8 × 2418)	=2347
If 50% QFs come on line = 413 + (.5 × 2418)	=1622
If 30% QFs come on line = 413 + (.3 × 2418)	=1138

(a) Sources:

1. SCE December 1984 Report on QF Power
2. Table 1 and 2 accompanying SCE motion of January 1985

SOUTHERN CALIFORNIA EDISON COMPANY

TIME DISTRIBUTION OF SIGNED QF CAPACITY(a)

	(MW)
Effective QF capacity signed prior to 12-31-82	= 666
Effective QF capacity signed during 1983	= 237
Effective QF capacity signed during 1984	=1928
Total	=2831

Time Distribution of QF Power

(MW)

Year	If all QFs materialize	If 80% materialize	If 50%	If 30%
1985.....	413*+84 = 497	413+67 = 460	413+42 = 455	413+25 = 438
1986.....	413+2(84)+79 = 660	413+198 = 611	413+124 = 537	413+74 = 487
1987.....	413+253+2(79)+643=1467	413+843 =1256	413+527 = 940	413+316= 729
1988.....	666+3(79)+2(643) =2189	413+1421=1834	413+1095=1508	413+533= 946
1989.....	666+237+1928 =2831	413+1936=2349	413+1210=1623	413+726=1139

* Already on line

(a) Source: SCE Quarterly Reports on Cogeneration and Small Power

SOUTHERN CALIFORNIA EDISON COMPANY

OF POWER(a) IN THE RESOURCE PLAN(b)

(MW)

Year	Cogen	Small Hydro	Biomass	Wind	Solar	Geother-mal	Fuel Cells	Total QFs
1984	28(13)	6	2	53	15	32	0	123
1985	199(13)	23	31	101	71	159(5)	0	566
1986	323(13)	25	123	118	97	216(5)	0	884
1987	358(13)	28	179	132	121	258(14)	0	1049
1988	393(13)	32	227	148	121	283(14)	0	1177
1989	728(13)	35	242	163	129(8)	308(14)	0	1570
1990	1013(13)	36	257	166	129(8)	332(14)	0	1826
1991	1048(13)	36	272	169	154(8)	357(14)	0	2001
1992	1083(13)	37	287	172	179(8)	382(14)	8(8)	2105
1993	1368(13)	37	302	175	204(8)	407(14)	30(30)	2458
1994	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1995	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1996	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1997	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1998	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1999	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
2000	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562

(a) Figures in parentheses show non-QF generation

(b) SCE Fall 1984 Resource Plan

SOUTHERN CALIFORNIA EDISON COMPANY

COMMITTED AND NONCOMMITTED RESOURCES

(MW)

Year	Total(a) Resources	QF(a) Power	Non-QF Resources	Non-QF(b) Non-Committed	Non-QF Committed Resources
(1)	(2)	(3)	(4) =(2)-(3)	(5)	(6) (6)=(4)-(5)
1985	17,654	566	17,088	0	17,088
1986	18,095	884	17,211	0	17,211
1987	18,377	1,049	17,328	0	17,328
1988	18,694	1,177	17,517	0	17,517
1989	19,010	1,570	17,440	0	17,440
1990	19,183	1,826	17,357	0	17,357
1991	19,582	2,001	17,581	0	17,581
1992	19,833	2,105	17,728	0	17,728
1993	20,284	2,458	17,826	0	17,826
1994	20,695	2,562	18,133	215	17,918
1995	21,145	2,562	18,583	665	17,918
1996	21,502	2,562	18,940	1,530	17,410
1997	21,882	2,562	19,320	2,230	17,090
1998	22,336	2,562	19,774	2,830	16,944
1999	22,662	2,562	20,100	3,796	16,304
2000	23,042	2,562	20,480	4,846	15,634
2001	23,352	2,562	20,790	5,446	15,344
2002	23,932	2,562	21,370	6,026	15,344
2003	24,132	2,562	21,570	6,576	14,994
2004	24,712	2,562	22,150	7,156	14,994

(a) Source: Fall '84 Resource Plan

(b) Resource additions expected from SCE hydro, PNW/PSW purchases and Pacific intertie expansion are treated as committed because of their low cost.

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SOUTHERN CALIFORNIA EDISON

SCENARIO 1: 50% OF QFS (NOT YET OPERATING) MATERIALIZE, WITH 1000 MW ADDITIONAL QFS

Year (1)	SCE Committed Resources (2)	QF Resources (3)	Total Committed Resources (4)=2+3	Projected Loads (5)	Reserve Margin (6)
1985	17088	455	17543	14420	22
1986	17211	537	17748	14730	20
1987	17328	940	18268	14960	22
1988	17517	1508	19025	15320	24
1989	17440	1623	19063	15660	22
1990	17357	1623	18980	16030	18
1991	17581	1623	19204	16390	17
1992	17728	1623	19351	16760	15
1993	17826	1623	19449	17140	13
1994	17918	1623	19541	17520	12
1995	17918	1623	19541	17880	9
1996	17410	1623	19033	18220	4
1997	17090	1623	18713	18560	1
1998	16944	1623	18567	18890	-2
1999	16304	1623	17927	19220	-7
2000	15634	1623	17257	19540	-12
2001	15344	1623	16967	19880	-15
2002	15344	1623	16967	20200	-16
2003	14994	1623	16617	20540	-19
2004	14994	1623	16617	20880	-20

Reserve Margin With 1000MW More QFs (7)	Average Reserve Margin (8)	Adjustment Factor (9)	Annualized Combustion Turbine Cost (10)	Present Worth Factor (11)	Adjusted Present Worth of Combustion Turbine (12)=9*10*11
22	21.7	0.89	83	1	73
20	20.5	0.96	89	0.8696	74
22	22.1	0.86	95	0.7561	61
26	25.3	0.64	102	0.6575	43
26	23.9	0.74	109	0.5718	46
25	21.5	0.89	116	0.4972	52
23	20.2	0.98	125	0.4323	53
21	18.4	1.00	133	0.3759	50
19	16.4	1.00	143	0.3269	47
17	14.4	1.00	153	0.2843	43
15	12.1	1.00	163	0.2472	40
10	7.2	1.00	175	0.2149	38
6	3.5	1.00	187	0.1869	35
4	0.9	1.00	200	0.1625	33
-2	-4.1	1.00	214	0.1413	30
-7	-9.1	1.00	229	0.1229	28
-10	-12.1	1.00	245	0.1069	26
-11	-13.5	1.00	262	0.0929	24
-14	-16.7	1.00	281	0.0808	23
-16	-18.0	1.00	300	0.0703	21
		1.00	321	0.0611	20
		1.00	344	0.0531	18
		1.00	368	0.0462	17
		1.00	393	0.0402	16
		1.00	421	0.0349	15
		1.00	450	0.0304	14
		1.00	482	0.0264	13
		1.00	516	0.0230	12
		1.00	552	0.0200	11
		1.00	590	0.0174	10
		1.00	632	0.0151	10
		1.00	676	0.0131	9
		1.00	723	0.0114	8
		1.00	774	0.0099	8
		1.00	828	0.0086	7
		1	886	0.0075	7

SOUTHERN CALIFORNIA EDISON

PRESENT FIRM CAPACITY PRICE SCHEDULES

FOR STANDARD OFFER #2:

CAPACITY PRICE OFFERS—FIRM ($/kW/Year)

Initial Operation Date Southern California Edison (SCE)	Duration of Contract (Years)					
	1	5	10	15	20	30
1985	83	92	105	116	125	138
1986	88	99	112	124	133	146
1987	94	105	120	132	143	155
1988	100	113	128	141	153	165
1989	107	121	137	151	164	175

FOR STANDARD OFFER #4:

Year of Initial Delivery	$/kW/Year Contract Term (Years)						
	1	5	10	15	20	25	30
1983	70	80	92	105	114	121	127
1984	76	86	100	113	123	131	137
1985	81	93	108	122	132	141	147
1986	87	100	117	131	143	152	158
1987	94	107	127	142	154	163	170
1988	101	117	137	153	166	176	184

PACIFIC GAS AND ELECTRIC
FIRM CAPACITY PRICE SCHEDULE
(LEVELIZED $/KW-YEAR)
FOR THE FIRST 1000 MW OF ADDITIONAL QF POWER

Scenario 1: Assume 30% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	7	19	44	59	70	77
1986	9	2	26	52	68	79	87
1987	0	1	38	64	81	92	100
1988	0	8	53	80	96	108	117
1989	0	21	72	98	115	127	136
1990	0	43	93	119	137	149	159
1991	5	75	119	144	162	175	185

Scenario 2: Assume 50% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	11	35	51	62	69
1986	6	2	15	42	59	70	78
1987	0	0	25	53	70	82	91
1988	0	1	39	67	85	97	106
1989	0	8	55	83	102	114	124
1990	0	21	74	103	121	135	144
1991	0	42	97	125	144	158	168

Scenario 3: Assume 80% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	19	5	4	24	40	51	59
1986	1	0	4	29	47	58	66
1987	0	0	10	39	57	69	78
1988	0	0	19	51	69	82	91
1989	0	0	33	64	84	97	107
1990	0	3	49	81	101	115	125
1991	0	11	68	100	121	135	146

Average Values from Scenarios 1, 2 and 3

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	10	34	50	60	68
1986	6	1	13	41	57	68	76
1987	0	0	23	51	68	80	89
1988	0	0	36	65	83	95	104
1989	0	5	52	81	99	112	121
1990	0	17	70	99	118	132	141
1991	0	37	93	122	141	155	165

Workpapers

Pacific Gas & Electric Company

General Assumptions

1. Peak-Availability of QFs

   a. All firm QFs have 80% average availability.

   b. Average peak availability for PG&E as-available wind and hydro QFs is 20% and 22% respectively. Cogeneration and solid waste QFs have 30% average peak availability.

2. Time Distribution of QFs

   a. ⅓ of materializing QFs come on line 3 years after signing the contract.

   b. ⅔ of materializing QFs are on line 4 years after signing the contract.

   c. All materializing QFs are on line 5 years after signing the contract.

3. Value of Capacity

   a. Up to 20% reserve margin, QF capacity is worth full gas turbine to the utility.

   b. At 35% reserve margin or above, the value of additional QF capacity is zero.

   c. Between 20-35% the value of QF capacity declines linearly from 1 to 0.

4. Capacity Cost

   a. Combustion turbine cost, inflation rate and discount rate same as adopted in the utility's last general rate case.

Pacific Gas and Electric Company

	MW
Total QF Capacity Signed (Nameplate) as of 12.31.84	=6,593
Firm	=3,550
As-Delivered	=2,992
Energy only	= 38
Parallel Generation	= 13
Effective Capacity	
Firm	=3,550
As-Delivered	=(149×.3)+(549×.22)+(.2×2295) =45+120+459 =624
Total Effective Peak Capacity	=3,550+624 =4,174
Already Operational (Nameplate)	=942
Out of if, wind+hydro	=379
Other	=563
Operational Effective Peak Capacity	=(379×.2)+563=640 approximately
Total Effective Peak Capacity not on line yet	=4,174−640 =3,534
Total effective peak capacity:	
if all QFs come on line	=640+3,534=4,174
if 80% QFs come on line	=640+(.8×3,524)=3,467 MW
if 50% QFs come on line	=640+(.5×3,524)=2,407 MW
if 30% QFs come on line	=640+(.3×3,524=1,700 MW

Pacific Gas & Electric Company

Time Distribution of QF Power

Effective capacity signed prior(1) to 12.31.82 ..... =814 MW
Effective capacity signed during(2) 1983 ..... =880
Effective capacity signed during(3) 1984 ..... =2,480
Total effective capacity as of 12.31.84 ..... =4,174

Time Distribution of QF Power

Year	If all materialize		If 80%	If 30%	If 50%
1985.....	640(4)+58=698		640+(.8x58)=686	657	669
1986.....	640 +2(58)+293	=1,049	640+(.8x409)=967	763	845
1987.....	640 +174+2(293)+827	=2,227	640+(.8x1,587)=1,190	1,116	1,433
1988.....	640 +174+880+2(827)	=3,348	640+(.8x2,708)=2,806	1,452	1,994
1989.....	640 +174+880+2,480	=4,174	640+(.8x3,534)=3,467	1,700	2,407

(1) PG&E Quarterly Report 12.31.82
(2) PG&E Quarterly Report 12.31.83
(3) PG&E Quarterly Report 12.31.84
(4) Already operational

Pacific Gas and Electric Company
QFs in the Resource Plan(a)

Year	Small Hydro	Cogeneration + Solid Waste	Geothermal	Wind and Solar	Yearly Total	Cumulative Total
As of 8-31-83	17(b)	331(179)	0	13(2.5)	179.5	179.5
1984 ..	7.5	82	80	11	180.5	360.0
1985 ..	7.4	103	0	30	140.4	500.4
1986 ..	7.1	427	0	15	449.1	949.5
1987 ..	5.3	346	0	22	373.3	1,322.8
1988 ..	4.0	79	0	45	128.0	1,450.8
1989 ..	4.0	75	0	31	110.0	1,560.8
1990 ..	4.0	75	0	33	112.0	1,672.8
1991 ..	4.0	69	0	29	102.0	1,774.8
1992 ..	4.0	68	0	34	101.0	1,875.8
1993 ..	4.0	38	0	40	82.0	1,957.8
1994 ..	4.0	38	0	55	97.0	2,054.8
1995 ..	4.0	38	0	20	62.0	2,116.8
1996 ..	4.0	50	0	25	79.0	2,195.8
1997 ..	4.0	50	0	25	79.0	2,274.8
1998 ..	4.0	50	0	24	78.0	2,352.8
1999 ..	4.0	50	0	22	76.0	2,428.8
2000 ..	4.0	50	0	21	75.0	2,503.8
2001 ..	4.0	50	0	30	84.0	2,587.8
2002 ..	4.0	50	0	28	82.0	2,669.8
2003 ..	4.0	50	0	27	81.0	2,750.8
2004 ..	4.0	50	0	24	78.0	2,828.8
Total...	112.3	2,035	80	601.5	2,828.8	2,828.8

(a) PG&E's Long-Term Plan, May 1984.
(b) Taken from 4th Quarter 1983 Report (85 × .2) = 17 MW.

PACIFIC GAS AND ELECTRIC COMPANY

NON-COMMITTED(a) NON-QF RESOURCES(b)

Year	Geo-thermal	Refurbish-ment	PG&E Unspeci-fied	Other Utility Uniden-tified	Yearly Addi-tion	Cumula-tive Total Addi-tion
1985	0	0	0	0	0	0
1986	0	0	0	0	0	0
1987	0	0	0	0	0	0
1988	0	0	0	0	0	0
1989	110	0	0	0	110	110
1990	110	214	0	0	324	434
1991	165	0	0	100	265	699
1992	110	0	0	0	110	809
1993	0	123	0	200	323	1,132
1994	0	234	0	0	234	1,366
1995	0	232	0	100	332	1,698
1996	0	326	0	100	426	2,124
1997	0	268	0	0	268	2,392
1998	0	326	250	250	826	3,218
1999	0	163	250	0	413	3,631
2000	0	163	500	150	813	4,444
2001	0	325	500	0	825	5,269
2002	0	325	500	0	825	6,094
2003	0	338	500	0	838	6,932
2004	0	338	500	0	838	7,770
Total ...	495	3,375	3,000	900	7,770	7,770

(a) Sources: May 1984 Long Term Resources plan and CFM-V filing.

(b) Imports of 245 MW and all projected hydro additions are treated as committed because of their possible low cost.

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PACIFIC GAS AND ELECTRIC

SCENARIO 1: 30% OF QFS (NOT YET ON LINE) MATERIALIZE, WITH 1000MW ADDITIONAL QFS

Year (1)	PG&E Committed Resources (2)	QF Resources (3)	Total Committed Resources (4)=2+3	Projected Loads (5)	Reserve Margin (6)
1985	19729	657	20386	15523	31
1986	20140	763	20903	15667	33
1987	20362	1116	21478	15883	35
1988	20620	1452	22072	16074	37
1989	20696	1700	22396	16254	38
1990	20536	1700	22236	16483	35
1991	20326	1700	22026	16770	31
1992	19970	1700	21670	17083	27
1993	19850	1700	21550	17378	24
1994	19619	1700	21319	17685	21
1995	19428	1700	21128	17961	18
1996	19105	1700	20805	18284	14
1997	18840	1700	20540	18684	10
1998	18517	1700	20217	19087	6
1999	18357	1700	20057	19495	3
2000	18194	1700	19894	19889	0
2001	17869	1700	19569	20407	−4
2002	17544	1700	19244	20892	−8
2003	17206	1700	18906	21405	−12
2004	16868	1700	18568	21931	−15

Reserve Margin With 1000MW More QFs (7)	Average Reserve Margin (8)	Adjustment Factor (9)	Annualized Combustion Turbine Cost (10)	Present Worth Factor (11)	Adjusted Present Worth of Combustion Turbine (12)=9*10*11
31	31.3	0.24	84	1	20
33	33.4	0.10	91	0.8696	8
35	35.2	0.00	98	0.7561	0
39	38.4	0.00	106	0.6575	0
42	39.8	0.00	115	0.5718	0
41	37.9	0.00	124	0.4972	0
37	34.3	0.04	132	0.4323	2
33	29.8	0.34	142	0.3759	18
30	26.9	0.54	152	0.3269	27
26	23.4	0.77	162	0.2843	36
23	20.4	0.97	174	0.2472	42
19	16.5	1.00	186	0.2149	40
15	12.6	1.00	199	0.1869	37
11	8.5	1.00	213	0.1625	35
8	5.4	1.00	228	0.1413	32
5	2.5	1.00	243	0.1229	30
1	−1.7	1.00	261	0.1069	28
−3	−5.5	1.00	279	0.0929	26
−7	−9.3	1.00	298	0.0808	24
−11	−13.1	1.00	319	0.0703	22
		1.00	342	0.0611	21
		1.00	365	0.0531	19
		1.00	391	0.0462	18
		1.00	418	0.0402	17
		1.00	448	0.0349	16
		1.00	479	0.0304	15
		1.00	513	0.0264	14
		1.00	548	0.0230	13
		1.00	587	0.0200	12
		1.00	628	0.0174	11
		1.00	672	0.0151	10
		1.00	719	0.0131	9
		1.00	769	0.0114	9
		1.00	823	0.0099	8
		1.00	881	0.0086	8
		1	942	0.0075	7

PACIFIC GAS AND ELECTRIC

PRESENT FIRM CAPACITY PRICE SCHEDULES

For Standard Offer #2:

Firm Capacity Price Schedule
(Levelized $/kW-year)

Actual Operation Date (Year)	Term of Agreement																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1983	72	111	96	88	84	85	88	91	93	96	98	100	102	104	106	115	122	128
1984	156	111	95	88	89	92	95	98	100	103	105	108	110	112	114	124	131	137
1985	60	58	59	66	73	79	84	88	92	95	99	102	104	107	110	121*	127*	135
1986	56	58	69	78	85	90	95	99	103	106	110	113	116	118	121	132	141	148
1987	61	77	88	95	101	105	109	113	117	120	124	127	130	132	135	147	156	163
1988	96	104	110	115*	119	122	126	129	133	136	139	142	145	148	151	163	173	180

For Standard Offer #4

Firm Capacity Price Schedule
(Levelized $/kW-year)

Firm Capacity Availability Date (Year)	Number of Years of Firm Capacity Delivery																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1982	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

APPENDIX B

10-Apr-85

SOUTHERN CALIFORNIA EDISON COMPANY

Cogeneration and Small Power Production

Cancelled Contracts and Letters of Intent
As of December 31, 1984

Project/ Development	Project Capacity (KW)	Technology	Comments
Acurex	12,000	Solar	Contract
California Alternate Power Sources	11,250	Wind	Contract
California Federal	2,400	Cogeneration	Letter of Intent
Carson Bio-Energy Company	2,100	Biomass	Letter of Intent
Central Plants— Irwindale	250	Biomass	Contract
Energy Recycling and Storage	100	Cogeneration	Letter of Intent
Hamilton Standard	20,000	Wind	Letter of Intent
Reichold Energy Corporation	1,300	Cogeneration	Letter of Intent
Shell California Production	150,000	Cogeneration	Contract
Solar World	3,900	Wind	Letter of Intent
Stinnet Oil	200	Cogeneration	Contract
United Ethanol of Delano	49,000	Biomass	Letter of Intent

APPENDIX F

Decision 86-10-038 October 16, 1986

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, and August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, and August 10, 1983)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983, and August 2, 1983)

Application 82-03-26 (Filed March 8, 1982)

Application 82-03-37 (Filed March 8, 1982)

Application 82-03-62 (Filed March 16, 1982)

Application 82-03-67 (Filed March 18, 1982)

Application 82-03-78 (Filed March 22, 1982)

Application 82-04-21 (Filed April 8, 1982)

Case 86-07-022 (Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.

And Related Matters.

OPINION ON PETITIONS OF ULTRAPOWER, INC., GWF POWER SYSTEMS, THERMAL ENERGY DEVELOPMENT CORP., AND BASIC AMERICAN FOODS RELATING TO PRICE TABLES IN PACIFIC GAS AND ELECTRIC'S INTERIM STANDARD OFFER 4

This decision resolves a dispute regarding the interpretation of certain provisions in contracts under our interim Standard Offer 4 for purchase by Pacific Gas & Electrc Company (PG&E) of electrical output from qualifying facility (QF) projects. We determine that PG&E's firm capacity price schedule must be

extended to include those years in which the QF projects, consistent with the terms of their respective contracts, may come online. We decline to extend those schedules relating to as-available capacity and forecasted energy prices.

I. Procedural History

This matter reaches us via three petitions for modification. Each petition addresses solely or primarily Decision (D.) 83-09-054, in which we approved interim Standard Offer 4 and made it available to QFs. The petitioners (all developers of QF projects) are: Thermal Energy Development Corporation (Thermal); GWF Power Systems Company (GWF); and Ultrapower Incorporated (Ultrapower). Thermal filed its petition on August 6, 1986; the other two petitions filed on August 11. [1]

PG&E and our Public Staff both responded to the petitions.[2] Also, Basic American Foods (Basic) on September 12 filed a "Petition for Consolidation and Expedited Resolution of the Firm

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[1] A fourth petition, filed August 22, 1986, for modification of D.83-09-054 also concerns (among other issues) PG&E's firm capacity price schedule in interim Standard Offer 4. However, the petitioners (El Dorado Irrigation District, El Dorado County Water Agency, and SOFAR Management Authority) filed a request on September 8 to withdraw their petition. We note no opposition to this request and believe it should be granted.

Finally, on October 8, 1986, Dexzel, Inc. (Dexzel), filed its petition for modification of D.83-09-054 as the decision relates to PG&E's firm capacity price schedule. This petition comes after PG&E had filed its response to Thermal, GWF, and Ultrapower; however, our resolution in today's decision of those petitions renders Dexzel's petition moot.

[2] Article 2.5 (Rules 8.1 to 8.8) of our Rules of Practice and Procedure governs various types of responsive pleadings, including objections to petitions for modification. See Rule 8.1(a). PG&E's response, filed on September 12, was timely under Rule 8.3. Public Staff's response was delayed until September 15. Public Staff indicated that the delay resulted from mechanical difficulties with the central wordprocessing system after the Commission's move to its new offices. In light of these circumstances, we grant Public Staff's request to accept this late filing.

Capacity Price Issue" in this proceeding (Application (A.) 82-04-44 et al.). The petition asserts that Basic is the complainant in Case (C.) 86-07-022 versus PG&E; that the case concerns in major part the same issue regarding PG&E's firm capacity price schedule that is raised in these three petitions for modification; that PG&E has already filed its responsive pleading (namely, a motion to dismiss) in C.86-07-022; and that resolution of this issue requires only the application of legal principles to facts not materially disputed. Further, Basic sets forth various reasons, associated with the construction and certification of its proposed American I Cogeneration Project, why delay in resolving this issue would adversely affect the project. Basic concludes that administrative efficiency and its own need for expedited resolution would both be served by granting the requested consolidation.

On October 3, 1986, PG&E submitted its "Reply to Basic American Foods' Petition for Consolidation and . . . Opposition to [PG&E's] Motion to Dismiss" for filing in both the complaint proceeding and in A.82-04-44 et al. PG&E does not oppose Basic's request for consolidation and expedited resolution; in fact, PG&E "urges that all the interim SO #4 price escalation issues be resolved together in one forum." (*Id.*, p. 3.)

We agree with Basic's and PG&E's reasoning in this regard and direct the consolidation of C.86-07-022 with A.82-04-44 et al. for the limited purpose of addressing the firm capacity price issue raised in the complaint.[3]

II. Factual Background

Interim Standard Offer 4 was our first attempt to implement power purchase contracts based on utilities' *long-run* avoided costs. Unlike the short-run standard offers (such as Standard Offer 1) whose price terms yield payments to QFs that vary in response to the purchasing utility's short-run needs, any long-run

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[3] Basic's petition suggests that resolution of this issue may make further litigation in C.86-07-022 unnecessary. In any event, we direct that litigation of issues from the complaint other than the issue addressed here be confined to the complaint proceeding.

standard offer involves the same sort of planning (such as lengthy forecasts of the purchasing utility's resource mix and costs) that goes into a utility decision to build a new power plant.

Properly implemented, a long-run standard offer can reduce risks both to QFs (who receive relatively greater price certainty than under short-run contracts) and to utilities (who defer or avoid major commitments of capital and various risks associated with new plant construction). However, long-run avoided costs are more elusive than are utilities' short-run marginal costs. Pending resolution of the various long-run avoided cost methodological issues, we convened a negotiating conference with the objective of establishing a long-run standard offer that the utilities could file "at least on an interim basis" and that "will be supported by the parties" to this proceeding. (D.83-05-038, mimeo., p. 7.)

The negotiating conference, at which utilities, QFs, and Commission staff participated vigorously, resulted in a proposal that we ratified as interim Standard Offer 4. (See generally D.83-09-054, mimeo.) For present purposes, the crux of interim Standard Offer 4 is the price certainty provided to QFs by a series of energy and capacity price schedules. These schedules set forth payments for firm capacity, as-available capacity, and a series of three energy payment options, all depending on the individual QF's period of operation (on-line date and length of contract).

The problem that we address in today's decision is that the schedules we approved in D.83-09-054, and continued in effect by D.84-08-035 (where we allowed interim Standard Offer 4 to remain available), were not expressly extended to consider all the years when QFs signing the interim offer might come on-line. Absent such extension, those QFs coming on-line after 1987 would have limited or no price certainty as to their capacity payments, energy payments, or both. All of the petitioners request extension of PG&E's firm capacity price schedule; in addition, Ultrapower seeks extension of PG&E's as-delivered capacity and forecasted energy price schedules.

A. PG&E's Firm Capacity Price Schedule[4]

In many respects, the negotiations drew directly from the already existing Standard Offers 1, 2, and 3 in putting together interim Standard Offer 4. This is especially clear with respect to pricing of firm capacity. Thus, for example, PG&E's Third Amendment (filed July 11, 1983) to A.82-04-44 in which PG&E sought approval of interim Standard Offer 4, says bluntly, "Payment for firm capacity is identical to that of Option 2, Standard Offer 2.... QFs selling firm capacity receive capacity prices which are levelized over their contract terms." (*Id.*, Part B, p. 3.) PG&E is equally emphatic with respect to the methodology by which the utility is to value capacity on its system: "[A]voided customer shortage costs (often referred to as 'capacity') ... are estimated by using the annual fixed costs of a combustion turbine as a proxy." (*Id.*, Part B, pp. 1-2.) This accords exactly with our contemporaneous understanding when we approved interim Standard Offer 4. (See D.83-09-054, mimeo., pp. 23, 26.) Furthermore, it is also clear that PG&E's Standard Offer 2, at the time of the negotiation and approval of interim Standard Offer 4, provided capacity payments based on the costs of a combustion turbine without upward or downward adjustment of those costs relative to PG&E's projected system reliability during the QF's period of performance. (See D.82-12-120, 10 CPUC 2d 553, 642-43 ordering paragraphs 7, 10.)

PG&E's Table E-2 is constructed under the foregoing principles, but it is completed only through 1987. Thus, those interim Standard Offer 4 QFs (such as the petitioners) with a firm capacity availability date later than 1987 need clarification as to the applicability of those principles to their contracts.[5] Petitioners

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[4] PG&E's interim Standard Offer 4 identifies this schedule as Table E-2, and we will use that label for convenience in the rest of today's decision.

[5] QFs must come on-line within five years of contract signing. (D.83-09-054, mimeo., p. 23.) Because interim Standard Offer 4 was not entirely suspended until April 1985 (see D.85-04-075), QFs signing the interim offer have as late as April 1990 (depending on when the QF signed) to become operational.

(supported by Public Staff) maintain that the principles govern firm capacity payments to all QFs coming on-line consistent with the provisions of their respective interim Standard Offer 4 contracts, and that PG&E could readily extend the payment schedule to encompass 1988, 1989, and 1990 by using the combustion turbine cost escalation factors already implicit in Table E-2. Petitioners also claim that the regulations of the Federal Energy Regulatory Commission (hereafter referred to as FERC rules) expressly give QFs supplying firm capacity the option to receive avoided capacity costs calculated for the term of the contract at the time the contractual obligation is incurred. (18 CFR § 292.304(d)(2).)[6] Interim Standard Offer 4, petitioners argue, bases firm capacity payments on this option, and accordingly Table E-2 must be extended to cover all potential periods of operation under the offer. PG&E maintains in essence that, because Table E-2 presently contains no payment schedule for QFs coming on-line after 1987, the principles do not apply at all to such QFs, and that such QFs should instead receive, by analogy to the Uniform Commercial Code as adopted in California, "a reasonable price at the time of delivery for firm capacity deliveries beginning after 1987." (PG&E, Protest to Petitions for Modification, p. 37.)

B. PG&E's As-Available Capacity Price Schedule[7]

Table D-2 contains forecasted shortage costs for each year from 1983 to 1997. In contrast with the treatment of prices for firm capacity, discussed above, this treatment of as-available capacity prices in interim Standard Offer 4 is a marked departure from the approach taken in any of our other standard offers,[8] and also goes far beyond anything required under the FERC rules.

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[6] The FERC rules implement the federal Public Utility Regulatory Policies Act. That statute and the implementing rules provide a federal framework for state regulation of dealings between utilities and QFs.

[7] This is Table D-2 in PG&E's interim Standard Offer 4, and we will henceforth use this label when referring to this schedule.

[8] Under Standard Offers 1 and 3, which are also contracts for as-available capacity, such capacity is repriced in each general rate case of

Ultrapower is the only petitioner seeking extension of Table D-2. Ultrapower notes that the "fixed price period" in PG&E's interim Standard Offer 4 is so defined as to provide 10 years (from the date of initial energy deliveries) of forecasted as-available capacity prices for a QF with a contract term of 20 years or more. However, unless Table D-2 is extended, interim Standard Offer 4 QFs coming on-line after 1987 could have as little as seven years of price certainty for as-available capacity.

PG&E and Public Staff oppose extension of Table D-2. Public Staff apparently takes the position that "fixed price period" should be construed together with Table D-2 to provide a *maximum* of 10 years of forecasted as-available capacity prices; thus, the fact that some interim Standard Offer 4 QFs would receive less than 10 years of price certainty does not, in Public Staff's view, violate the letter of the contract or the Commission's intent. PG&E argues that "the Commission only approved the 15-year forecast agreed to during the negotiating conference. The number in the adopted forecast cannot rationally be extended beyond 15 years. Negotiation, not methodology tested by evidentiary hearings, generated the numbers." (PG&E, Protest to Petitions for Modification, pp. 19-20.)

C. PG&E's Forecasted Energy Price Schedule[9]

Table B-1 relates to Energy Payment Option 1 and contains energy prices, differentiated by on-peak, partial-peak, and off-peak deliveries, for each year from 1983 to 1997. This table departs radically from the computation of energy prices under any of the other standard offers then extant. Our practice for the short-run offers was and is to price energy as the product of the purchasing utility's incremental fuel cost (updated quarterly) times that utility's incremental energy rate (updated in the general rate case).

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the purchasing utility. At the time we approved interim Standard Offer 4, PG&E had a general rate case every two years.

[9] Identified in PG&E's interim Standard Offer 4, and hereafter in today's decision, as Table B-1.

Ultrapower, again, is the only petitioner seeking extension of Table B-1.[10] Ultrapower again bases its theory in support of extension on its interpretation of "fixed price period" in interim Standard Offer 4. Ultrapower would derive energy prices for the additional years "based on the input assumptions underlying Table B-1 which were applicable at the time Table B-1 was generated. In the alternative, forecasted energy price values for the years 1998 and 1999 may be easily established equal to the 1997 value plus one cent per kilowatt hour each year as an expedient way of providing an energy price term. This is consistent with Southern California Edison Company's resolution of the same issue." (Ultrapower, Petition for Modification, p. 7.)

PG&E and Public Staff oppose extension of Table B-1. Their arguments are quite similar. They note that the energy forecasts in interim Standard Offer 4 were adopted solely as the result of negotiation and without an evidentiary record other than the fact that the forecasts were agreed to. Consequently, according to PG&E and Public Staff, there is no evidentiary basis for extending Table B-1 beyond the years already included. PG&E makes the further point that, although we decided ultimately to make interim Standard Offer 4 available for a longer period than we had originally anticipated, the decision (D.84-08-035) in which we continued the offer's availability does not revise the previously adopted prices or forecasts despite one request for partial revision. Specifically, Independent Energy Producers Association (IEP) had requested that the incremental energy rates used in one of the payment options (Energy Payment Option 3, not at issue in these petitions) be modified based on more recent information. We rejected the request, noting that each payment option is:

> "part of the negotiated package which the Commission approved in D.83-09-054. A change in one term would require the reexamination of all other terms of the standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the eviden-

[10] Specifically, Ultrapower seeks extension of the table to include the years 1998 and 1999.

tiary hearings now scheduled in this proceeding. We also note that a QF who finds the terms of interim Standard Offer No. 4 unacceptable may in fact negotiate a separate contract." (D.84-08-035, mimeo., p. 4.)

III. Discussion

A. Table E-2

We think that a fair reading of PG&E's interim Standard Offer 4 makes clear that firm capacity QFs holding contracts under that offer are entitled to levelized payments for such capacity over the term of their contracts. Consequently, Table E-2 must be extended to provide a firm capacity price schedule for all years in which such QFs are entitled to become operational (i.e., within five years of signing the contract). Our examination of D.83-09-054 (approving interim Standard Offer 4) and the FERC rules strongly confirms this reading. Furthermore, we agree with petitioners that the extension is ministerial, given that we specified the appropriate discount rate in D.83-09-054, and the combustion turbine cost escalation factors are already implicit in Table E-2.[11]

The extension of Table E-2 applies to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. All of the petitioners apparently hold contracts showing on-line dates in 1987 or earlier. QFs such as petitioners who come on-line later than the date specified in their contracts but consistent with the five-year deadline retain their original firm capacity payment schedule but are *not* entitled to escalation. The firm capacity price for these QFs was calculated and fixed when their contractual obligation was incurred, on the

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[11] We note that PG&E itself (in a petition for modification of D.83-12-068) has argued that extension of a firm capacity price schedule for purposes of Standard Offer 2 constitutes a "ministerial act." Not surprisingly, PG&E has asked to withdraw that petition. We have not as yet ruled on the petition or the request, nor do we do so here, as the petition was filed in another proceeding (A.82-12-48).

basis of the operational date they themselves specified in their respective contracts.

PG&E's opposition is predicated chiefly on the theory that to extend Table E-2 would constitute retroactive reformation, contrary to law and to our stated intentions in approving interim Standard Offer 4. But this theory collapses because we are *not* supplying missing terms but rather construing the express terms to give them their clear and logical effect. PG&E's interpretation, on the other hand, contradicts every mention of firm capacity in the relevant documents. Furthermore, PG&E construes an ambiguity (namely, the silence of Table E-2 for the years 1988, 1989, and 1989) so as to cause an essential contract term to fail for indefiniteness. This is contrary to general rules for construing contracts. Finally, PG&E's suggested resolution of the ambiguity is wholly arbitrary: we find not the slightest suggestion, in interim Standard Offer 4 itself or any other relevant source, that the Commission would or could simply make up firm capacity prices as it went along.[12]

PG&E argues that the petitions should be rejected because granting them would increase costs to PG&E, and ultimately ratepayers. This argument (1) ignores the language of interim Standard Offer 4, and (2) requires a crystal ball. The fact is, neither we, nor PG&E, nor QFs know whether the escalation factors in Table E-2 will prove higher or lower than the change in costs of a combustion turbine, or than inflation generally. Furthermore, PG&E has said repeatedly and in many proceedings that it is currently flush with capacity. Logically, then, the firm capacity provided by petitioners and similarly situated QFs will have greater value to PG&E if they come on-line later rather than

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[12] Our failure in D.84-08-035 (continuing the availability of interim Standard Offer 4) to specifically address Table E-2 is not at all surprising, given the identical treatment of firm capacity payments in Standard Offer 2. In fact, for almost a year after we suspended interim Standard Offer 4, new QFs could continue to obtain levelized payments for up to 30 years for firm capacity under Standard Offer 2.

sooner. The escalation factors in Table E-2 do not consider this at all.[13]

B. Tables D-2 and B-1

We reject Ultrapower's request for extension of these tables. Unlike firm capacity pricing, there is no analogue in our other standard offers for the treatment of as-available capacity and energy payments in these tables, and no accepted methodology for extending them.

We regret that our decisions did not address this point specifically; however, both D.83-09-054 and D.84-08-035 contain clear indications that we preferred finalizing our long-run avoided cost methodology to extension of these tables. Our rejection in D.84-08-035 of IEP's request to revise the incremental energy rates was noted earlier. In D.83-09-054 (mimeo., p. 33), we expressed strong reservations concerning the levelized energy payments provided by Option 2 (not at issue in these petitions) of interim Standard Offer 4. To find by implication that the utilities are now *compelled* to extend Tables D-2 and B-1 cannot be justified by reference to interim Standard Offer 4 or the decisions approving that offer.[14]

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[13] PG&E also does not consider the possibility that some of the petitioners and similarly situated QFs may be able to accelerate their development schedules in order to come on-line by the end of 1987 (the last year for which Table E-2 presently shows a price schedule). Such accelerated development would compound the minimum load problems that PG&E claims QFs impose on its system.

[14] Our interpretation of Tables D-2 and B-1 leaves petitioners with at least seven years of price certainty. In contrast, PG&E's interpretation of Table E-2 would leave petitioners with *no* price certainty (as to firm capacity payments).

We emphasize that we do not preclude utilities from completing Tables D-2 and B-1 to provide 10 years of price certainty, based on the data and escalation factors already in the tables.

Findings of Fact

1. The petitions of Ultrapower, GWF, and Thermal for modification of D.83-09-054 and (in Thermal's case) D.82-12-120 request that Table E-2 of PG&E's interim Standard Offer 4 be extended to provide a firm capacity price schedule for QFs coming on-line in the years 1988, 1989, and 1990. The complaint of Basic American Foods in C.86-07-022 requests similar relief.

2. The petition of Ultrapower for modification of D.83-09-054 requests that Tables D-2 and B-1 of PG&E's interim Standard Offer 4 be extended to provide as-available capacity and forecasted energy prices through the year 1999.

3. Interim Standard Offer 4 is the result of a negotiating conference at which the parties agreed on a series of energy and capacity price schedules. The purpose of the schedules is to provide a contract with price certainty equal to or greater than that provided to QFs under Standard Offers 1, 2, and 3.

4. The intent of Table E-2, and other provisions in interim Standard Offer 4 regarding firm capacity QFs, is to establish a payment schedule for firm capacity calculated for the term of the contract at the time the contractual obligation is incurred. This treatment of firm capacity pricing is identical to one of the payment options available to firm capacity QFs under Standard Offer 2.

5. Extension of Table E-2, as requested by petitioners, is essentially ministerial.

6. Tables D-2 and B-1, and other provisions of interim Standard Offer 4, do not guarantee to all QFs signing that offer the same number of years of price certainty regarding as-available capacity and energy payments, irrespective of the year that the QF becomes operational.

7. D.83-09-054 and D.84-08-035 indicate that we did not intend to extend our projections of energy and as-available capacity values before resolution of long-run avoided cost methodological issues.

Conclusions of Law

1. C.86-07-022 should be consolidated with this proceeding for the limited purpose of resolving the firm capacity price issue raised in that complaint. The petition of Dexzel for modification of D.83-09-054 should be dismissed as moot.

2. The request of Public Staff to accept its late-filed response to the petition of Ultrapower should be granted.

3. The request of El Dorado Irrigation District, El Dorado County Water District, and SOFAR Management Authority to withdraw their petition for modification of D.83-09-054 should be granted.

4. Table E-2 of PG&E's interim Standard Offer 4 should be extended to include the years 1988, 1989, and 1990. The extension of Table E-2 should apply to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. QFs who come on-line later than the date specified in their contracts but consistent with the five-year deadline should retain their original firm capacity payment schedule but are not entitled to escalation.

5. Tables D-2 and B-1 of PG&E's interim Standard Offer 4 should not be extended.

ORDER

1. The petition of Basic American Foods for partial consolidation of Case 86-07-022 with Application 82-04-44 et al. for the purpose of resolving the firm capacity pricing issue is granted. This order resolves that issue.

2. The request of the Public Staff Division to accept its late-filed response to the petition of Ultrapower, Inc. (Ultrapower), for modification of Decision 83-09-054 is granted.

3. The request of El Dorado Irrigation District, El Dorado County Water Agency, and SOFAR Management Authority to withdraw their petition for modification of Decision 83-09-054 is granted.

4. The petitions of Ultrapower, GWF Power Systems Company (GWF), and Thermal Energy Development Corporation (Thermal) for modification of Decision 83-09-054 and (in Thermal's case) Decision 82-12-120 are granted to the extent such petitions seek extension of Table E-2 in interim Standard Offer 4 of Pacific Gas & Electric Company (PG&E) to include the years 1988, 1989, and 1990.

5. Except to the extent granted in ordering paragraph 4, the petitions of Ultrapower, GWF, and Thermal are denied. The petition of Dexzel, Inc., for modification of Decision 83-09-054 is dismissed.

6. Within 20 days of the effective date of this order, PG&E shall file amendments to Table E-2 (firm capacity price schedule) in PG&E's interim Standard Offer 4, consistent with ordering paragraph 4 herein, using a discount rate of 15% (as ordered in Decision 83-09-054) and the combustion turbine cost escalation factors implicit in the table.

7. The amendments to be filed by PG&E in accordance with ordering paragraph 6 constitute a ministerial extension of Table E-2 pursuant to existing provisions of PG&E's interim Standard Offer 4. As such, the amendments shall govern the respective rights and obligations of PG&E and qualifying facilities contracted to sell electricity to PG&E under interim Standard Offer 4 contracts.

8. The extension of Table E-2 applies to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. QFs who come on-line later than the date specified in their contracts but consistent with the five-year deadline retain their original firm capacity payment schedule.

This order is effective today.

Dated October 16, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

I abstain.
STANLEY W. HULETT, Commissioner

APPENDIX G

Decision 86-12-013 December 3, 1986

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application 82-04-44
(Filed April 21, 1982;
amended April 28, 1982,
July 19, 1982, July 11, 1983,
August 2, 1983,
and August 21, 1986)

Application 82-04-46
(Filed April 21, 1982;
amended May 12, 1982,
July 11, 1983, August 10, 1983,
October 27, 1983,
January 4, 1984, May 4, 1984,
June 20, 1984,
and August 20, 1986)

Application 82-04-47
(Filed April 21, 1982;
amended July 11, 1983,
August 2, 1983,
September 6, 1984,
and August 20, 1986)

Application 82-03-26
(Filed March 8, 1982)

Application 82-03-37
(Filed March 8, 1982)

Application 82-03-62
(Filed March 16, 1982)

Application 82-03-67
(Filed March 18, 1982)

Application 82-03-78
(Filed March 22, 1982)

Application 82-04-21
(Filed April 8, 1982)

Case 86-07-022
(Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters.

ORDER MODIFYING DECISION 86-10-038

I. Introduction

By Decision (D.) 86-10-038, we interpreted certain payment provisions in interim Standard Offer 4 contracts between qualifying facilities (QFs) and Pacific Gas and Electric Company (PG&E). The decision responded to several petitions for modification of D.83-09-054 and also to a complaint (Case 86-07-022) that in part concerned the same issue of interpretation. Various parties have applied for rehearing of D.86-10-038.[1] The issues presented in the rehearing applications boil down to two: (1) which date (the "scheduled operation date" or the "firm capacity availability date") determines the firm capacity price; and (2) what should be done about prices in years that appear to come within the "fixed price period" of a given QF but that presently do not have prices indicated in the relevant payment schedules in PG&E's interim Standard Offer 4.

We address only the first issue in today's decision because, unfortunately, D.86-10-038 creates a serious ambiguity in this regard and should be clarified immediately. The second issue will be the subject of a later decision.

[1] The applicants for rehearing are: PG&E, Independent Energy Producers Association (IEP); Foster Wheeler Power Systems, Inc. (Foster); Ultrapower, Inc. (Ultrapower); and Basic American Foods (Basic).

II. Firm Capacity Availability Date

When in D.86-10-038 we analyzed the question of extending Table E-2, which is the firm capacity price schedule in PG&E's interim Standard Offer 4, we referred several times to the QFs "on-line" or "operational" date. (See D.86-10-038, mimeo., p. 11.) Unfortunately, PG&E's interim Standard Offer 4 contract form refers both to a "*scheduled operation date*" (see Article 3(c)), which is the day that (in the QF's estimation) the facility will first produce energy for delivery to PG&E, and to a *firm capacity availability date*" (see Article 5), which may be some time after the QF's first energy deliveries. The QF specifies its estimate of the date of scheduled operation when signing the contract; the date of firm capacity availability is *not* specified, but it is the latter date that dictates the firm capacity price in Table E-2. The use of the two different dates in the contract requires clarification of our use of the terms "on-line" and "operational" date.

We have concluded, in light of the specification of "firm capacity availability date" in Table E-2, that we cannot require the firm capacity price to be determined from the date of initial energy delivery. Regardless of the date that the QF scheduled for initial energy delivery at time of contract signing, so long as the QF is otherwise in compliance with its contract, the QF is entitled to have its firm capacity price determined in accordance with Table E-2, based on the date that the QF delivers firm capacity to the utility. (See definition of "*firm capacity availability date*" in Appendix A of PG&E's interim Standard Offer 4.)[2]

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[2] We will not, however, require PG&E to extend Table E-2 beyond 1990. We fully suspended the availability of interim Standard Offer 4 in April 1985; thus, consistent with the requirement that the QF must begin power deliveries within five years of contract signing (see Article 10), all interim Standard Offer 4 QFs will have had to begin power deliveries by April 1990. We think it is reasonable in this context to expect that most QFs in such a situation could achieve firm capacity within eight months, i.e., by the end of 1990. (We note that Basic, at page 7 of its application for rehearing, asserts that the "shakedown and testing period," starting from initial turbine roll, "is typically between 45 and 90 days in duration.") In any event, such QFs are not inherently

Finding of Fact

The use of the terms "scheduled operation date" and "firm capacity availability date" in PG&E's interim Standard Offer 4 makes ambiguous our analysis in D.86-10-038 of the firm capacity price schedule in that offer.

Conclusion of Law

The QF under PG&E's interim Standard Offer 4 is entitled to have its firm capacity price determined in accordance with Table E-2, based on the date that the QF makes firm capacity available to the utility.

Therefore, IT IS ORDERED that Decision 86-10-038 is modified as follows:

1. The first full paragraph of page 11 (at lines 7-17 of that page) is deleted.

2. The second and third sentences of Conclusion of Law 4 are deleted.

3. Ordering Paragraph 8 is deleted.

This order is effective today.

Dated December 3, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

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entitled to an indefinite capacity price extension, especially when the offer's availability had been suspended more than five years previously.

APPENDIX H

Decision 86 12 104 December 22 1986

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application 82-04-044
(Filed April 21, 1982;
amended April 28, 1982,
July 19, 1982, July 11, 1983,
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Application 82-04-046
(Filed April 21, 1982;
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October 27, 1983, January 4, 1984,
May 4, 1984, June 20, 1984,
and August 20, 1986)

Application 82-04-047
(Filed April 21, 1982;
amended July 11, 1983,
August 2, 1983, September 6, 1984,
and August 20, 1986)

Application 82-03-26
(Filed March 8, 1982)

Application 82-03-37
(Filed March 16, 1982)

Application 82-03-62
(Filed March 16, 1982)

Application 82-03-67
(Filed March 18, 1982)

Application 82-03-78
(Filed March 22, 1982)

Application 82-04-21
(Filed April 8, 1982)

Case 86-07-022
(Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters

ORDER DENYING REHEARING AND MODIFYING DECISION 86-10-038

PACIFIC GAS AND ELECTRIC COMPANY (PG&E), BASIC AMERICAN FOODS, INC. (Basic), FOSTER WHEELER POWER SYSTEMS, INC. (Foster), INDEPENDENT ENERGY PRODUCERS' ASSOCIATION (IEP), AND ULTRAPOWER, INC. (Ultrapower) have filed applications for rehearing of Decision (D.)86-10-038. We have considered all allegations of error raised in those applications and are of the opinion that the applications of Basic, Foster, and Ultrapower are moot and that sufficient reason for granting rehearing has not been shown in the applications of PG&E and IEP.

However, we find that the allegation of IEP with respect to the extension of Table B-1, which establishes energy prices through 1997, is well taken. The intent of the parties in placing Table B-1 into interim Standard Offer 4 (interim SO4) was to provide energy price certainty for up to ten years for each QF signing under that contract. Without the requested extension, those QFs coming online after 1987 do not have such price certainty. The same is true for Table D-2, which represents as-available capacity prices. We will accordingly extend these Tables to cover the years 1998-2000.

We will not, however, carry forward the price escalation of those tables into the three extended years, as we did with Table E-2 values in D.86-10-038. That table is merely an expression of the values of the agreed-upon price proxy, the cost of a combustion turbine (CT), carried over all applicable years. The change due to escalation was thereby made merely ministerial. Tables B-1 and D-2, on the other hand, are based on negotiations between the parties, which cannot be replaced without long and complex hearings for the sole purpose of adopting a workable methodology. Such hearings for the purpose of determining the increment or

decrement for three years' worth of pricing would be of far more cost than benefit to all concerned.

We are aware that in some instances utilities and QFs have agreed on escalated prices for missing years under the schedules discussed above. Our action today is not intended to vacate such agreements or to critique their reasonableness. As stated above, we have consistently encouraged utilities and QFs to reach accommodation short of litigating disputes before us or other tribunals. There may well be other difficult questions of interpretation lingering in the standard offers. We think it clear that everyone's efforts are best put to use in this proceeding on refinements to resource planning, capacity valuation, and updating for *prospective* application to QF/utility transactions. It is not the business of this Commission or the utilities to adjust for current perceptions of oversupply by harsh dealing toward QFs already under contract.

The simplest method of completing the ten years of price certainty in these tables is to carry the last value, that of 1997, forward over the next three years. This method at least provides price certainty and sets the price at the last negotiated price level; if the price is too high or too low, then the harm suffered by either the utility or the QFs will thus be minimized. Therefore,

IT IS ORDERED that,

1. The applications for rehearing are hereby denied.

2. PG&E is hereby ordered to file amendments to Tables B-1 and D-2 to interim Standard Offer 4, extending the 1997 prices of both tables into the years 1998, 1999 and 2000. This filing shall take place within 30 days of the effective date of this order.

3. Decision 86-10-038 is modified as follows:

a. Section III.B is deleted (*mimeo.*, pp. 12-13).

b. The sixth line from the bottom of *mimeo.* p.10 is deleted, so that Section III.A becomes Section III.

c. Finding of Fact 6 is modified to read:

"Tables D-2 and B-1, and other provisions of interim Standard Offer 4, do not guarantee to all QFs signing that offer

the same number of years of price escalation regarding as-available capacity and energy payments, irrespective of the year that the QF becomes operational, but they do guarantee a minimum of up to ten years of price certainty."

d. Conclusion of Law 5 is modified to read:

"Tables D-2 and B-1 of PG&E's interim Standard Offer 4 should be extended through the year 2000, but not escalated beyond the prices forecast for 1997."

This order is effective today.

Dated December 22, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

Commissioner G. Mitchell Wilk
present but not participating.

APPENDIX I

DEC. NO. 86-12-104 Mailed 12/26/86

Copy of: ORDER DENYING REHEARING AND MODIFYING DECISON 86-10-038 mailed to the following:

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APPENDIX J

Before the Public Utilities Commission
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Consolidated Application No. 82-04-044 and
Application No. 82-03-026
Second Application of PACIFIC GAS AND ELECTRIC COMPANY
for approval of Certain Standard Offers
Pursuant to Decision No. 82-01-103
in Order Instituting Rulemaking No. 2
(U-39E)

Application for Rehearing
of Decision 86-10-038
by Pacific Gas and Electric Company

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Before the Public Utilities Commission
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Application No. 82-03-026

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(U-39E)

Application for Rehearing
of Decision 86-10-038
by Pacific Gas and Electric Company

I
INTRODUCTION

In accordance with California Utilities Code § 1731 and Rule 85 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PGandE") requests rehearing of those portions of Decision 86-10-038 (the "Decision") issued October 16, 1986 which pertain to the firm capacity price payable under interim Standard Offer No. 4 power purchase agreements to sellers that establish firm capacity availability dates after 1987.

The Decision gives sellers who initially promised to begin operations by the end of 1987 the right to retain the corresponding prices set forth in the contract even in the event they delay the start of operations past 1987. It further gives sellers who initially promised to begin operations after 1987 new firm capacity prices even higher than those set forth in their power purchase agreements. The additional cost to PGandE ratepayers will be substantial. In ordering changes to the fixed firm capacity prices, the Decision works changes in executed interim SO4 agreements that cannot be countenanced under ordinary rules of contract interpretation, that counter the Commission's own prohibition against retroactive modification to interim SO4 agreements and that violate the Public Utility Regulatory Policies Act of 1978 ("PURPA").

II
BACKGROUND

Decision 86-10-038 responded to Petitions for Modification of Decisions 83-09-054 and 82-12-120 by Thermal Energy Development Corporation, GWF Power Systems, Inc. and Ultrapower, Inc. The complaint of Basic American Foods, Inc. (C.86-07-022) was consolidated with these petitions for the purpose of resolving the firm capacity price schedule. (Collectively, "petitioners"). In the interim SO4 contracts for each of their seventeen projects, petitioners stated that the scheduled operation date was 1987 or earlier.

Petitioners each requested that new, higher prices for firm capacity deliveries beginning after 1987 be added to their executed interim SO4 power purchase agreements. The last price in Table E-2 of interim SO4 specifies a levelized price of $160/kw-year for thirty years of firm capacity deliveries beginning in 1987. Article 12 of interim SO4 states that the contract terminates unless energy deliveries begin within five years of contract execution.

Petitioners argued Article 12 implicitly entitled them to new firm capacity prices based on an escalation of the existing interim SO4 contract prices if they begin firm capacity deliveries after 1987 but within the five-year deadline. Ultrapower also argued that the fixed forecasted energy (Table B-1) and as-delivered capacity (Table D-2) price schedules should be similarly extended so that sellers beginning deliveries of energy and as-delivered capacity within the five-year period could receive ten years of fixed prices.

Decision 86-10-038 rejected Ultrapower's request to extend the energy and as-delivered capacity price schedules. The Commission concluded that neither interim SO4 or its decisions regarding interim SO4 justified the extension of those schedules by implication. However, the Commission reached the opposite conclusion with respect to the firm capacity price schedule. The Decision orders PGandE to add new firm capacity prices for years 1988 to 1990 to Table E-2. The Decision makes these new prices available only to sellers which initially specified operation dates after

1987 in their interim SO4 contracts. It allows sellers such as petitioners which specified operation dates prior to the end of 1987 to retain the original Table E-2 prices even though they begin firm capacity deliveries after 1987. But such sellers are not eligible to receive the new prices.

PGandE concurs in the Commission's decision that extension of the energy and as-delivered price schedules cannot be justified. But the same reasoning which made extension of Table B-1 and Table D-2 unjustifiable applies also to Table E-2. The Decision's extension of Table E-2's availability and addition of new escalated prices is contrary to the express language of interim SO4. It cannot be sustained as mere contract interpretation. It accordingly violates both the Commission's own prohibition against retroactive changes to executed interim SO4 agreements and PURPA.

III
DISCUSSION

A. The Express Terms Of Interim SO4 Preclude Implication Of New Fixed Firm Capacity Prices Derived From An Escalation Of Table E-2

The keystone of the Decision's extension and escalation of the firm capacity price schedule is that it is "*not* supplying missing terms but rather construing the express terms to give them their clear and logical effect." Mimeo p. 11 (Emphasis in original). Interim SO4 as approved by the Commission in Decision 83-09-054 and extended in Decision 84-08-035 undeniably does not contain any prices for firm capacity deliveries after 1987. The express language of interim SO4 precludes the implication of any new prices. Accordingly, the Decision's order that PGandE extend the availability of Table E-2 and add new escalated prices cannot be sustained.

1. Rules Of Contract Interpretation Do Not Permit Implication Of New Escalated Prices

The Decision states that interim SO4 entitles firm capacity sellers to levelized firm capacity prices throughout the contract

term./Mimeo, p. 10./Interim SO4 makes no such promise. Article 5 states only that payment shall be "determined in accordance with Appendix E." Appendix E, Section E-1 refers only to the "*firm capacity prices* in Table E-2." (Underscoring in original.) Section A-2 defines "firm capacity price" only in reference to Table E-2. It is:

> the price for *firm capacity* applicable for the *firm capacity availability date* and the number of years of *firm capacity* delivery from the *firm capacity price schedule,* Table E-2, Appendix E.

Accordingly, interim SO4 nowhere expressly promises the seller that it will receive fixed levelized firm capacity prices throughout its term of agreement no matter when it begins firm capacity deliveries. To the contrary, interim SO4 repeatedly and consistently states that the firm capacity prices are those contained in Table E-2. Those prices end after 1987. Thus, interim SO4 only promised fixed levelized firm capacity prices to sellers that begin firm capacity deliveries by the end of 1987.

The Decision can only be sustained if the extension of Table E-2's availability and new prices it ordered be added to executed interim SO4 contracts are already part of those agreements by implication. But interim SO4 cannot be so construed. The Commission has stated that the standard offers are to be "a contract in the 'traditional' legal sense." Decision 85-06-163, Mimeo, p.29 (June 21, 1985). Ordinary rules of contract interpretation therefore apply.

Implied terms are not favored. *Cousins Investment Co. v. Hastings Clothing Co.,* 45 Cal. App. 2d 141, 143 (1941). Terms in an agreement may be implied only if each of the following conditions are met:

> (1) the implication must arise from the language used or it must be indispensable to effectuate the intention of the parties; (2) it must appear from the language used that it was so clearly within the contemplation of the parties that they deemed it unnecessary to express it; (3) implied covenants can only be justified on the grounds of legal necessity; (4) a promise can be implied only where it can be rightfully

> assumed that it would have been made if attention had been called to it; and (5) there can be no implied covenant where the subject is completely covered by the contract.

Hinckley v. Bechtel Corp., 41 Cal. App. 3d 206, 211 (1974). An implied term cannot rest solely on the facts surrounding the execution of a contract. "It must have a basis in the contract itself." *Stockton Dry Goods Co. v. Girsh*, 36 Cal. 2d 677, 680-681 (1950). "Legal necessity" is the single most important factor. *Hinckley, supra*, 41 Cal. App. 3d at 212. The language of interim SO4 does not permit the implication of new escalated fixed prices for firm capacity deliveries beginning after 1987. Nor is the implication of such prices necessary to salvage the agreement. Accordingly, under the rules cited above, no such prices can be implied.

The express language of interim SO4 precludes the implication of fixed escalated prices after 1987. Article 12 is the only express term in interim SO4 on which the Decision relies for in its conclusion that Table E-2 should be extended. Article 12 specifies the term of agreement. For firm capacity sellers, it provides that:

> This Agreement shall be binding upon execution and shall remain in effect for ____ years from the *firm capacity availability date*; provided, however, that it shall terminate if energy deliveries do not start within five years of the execution date.

The only conceivable basis in interim SO4 for implying extended and escalated prices is the difference between the Article 12 and Table E-2 timetables. But the difference does not allow implication of fixed, escalated post-1987 prices under the rules cited above.

First, Article 12 and Table E-2 are not inconsistent. The difference in their timetables does not create any ambiguity. The two provisions are entirely independent. Interim SO4 does allow a seller to delay operation for up to five years before the agreement automatically terminates. But interim SO4 does not guarantee that the seller will receive the same firm capacity price that it would have received but for the delay, let alone a price that is even higher than those specified in Table E-2. The Decision

attempts to make the Article 12 and Table E-2 timetables run concurrently. But the express terms of those provisions separate the two timetables.

If a seller wishes to avoid termination under Article 12, it must begin "energy deliveries" within five years. But if a seller wishes to secure a fixed levelized firm capacity price under Table E-2, it must establish a "firm capacity availability date" by the end of 1987. That date is much different than the date on which energy deliveries begin. It is:

> The day following the day during which all features and equipment of the *Facility* are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver *firm capacity* continuously into PGandE's system as provided in this Agreement.
>
> Interim SO4, Section A-1.

Consequently, even under the Decision, a seller can begin energy deliveries within the five-year deadline, but still not establish a firm capacity availability date until much later. The logic of the Decision's effort to force identity between the five-year timetable and the Table E-2 timetable would thus lead to the absurdity that the firm capacity prices should be extended not merely to meet the five-year deadline, but indefinitely.

The independence between the Article 12 five-year deadline and the Table E-2 prices has been apparent from the inception of interim SO4. Interim SO4 was authorized for use in Decision 83-09-054 issued on September 7, 1983. The Article 12 five-year deadline could occur no sooner than 1988. Yet the Table E-2 prices expire at the end of 1987.

This obvious lack of correspondence shows the timetables were intended to be different, not that the prices should be implicitly extended. The five-year deadline in Article 12 sets an outside limit on development of a project. It accordingly assists in generation and transmission resource planning. Interim SO4 otherwise provides no direct control on when a project must begin operations. Article 12 also serves to reduce speculation and eliminate stale contracts. But Article 12 does not contain any

reference to prices. It contains no guarantee that a seller beginning operations after 1987 will retain the Table E-2 prices, let alone secure higher prices. Since neither the language of Article 12 nor its purpose require consistency with Table E-2, it cannot be interpreted to imply extended or escalated firm capacity prices.[1]

Moreover, even if it were possible to construe the five-year provision to govern Table E-2, the Decision further declares not only that the time period during which the Table E-2 prices are available is impliedly extended, but that the prices themselves must be impliedly escalated. Article 2 precludes any interpretation of interim SO4 which would imply the addition of new prices based on an escalation of Table E-2 in executed interim SO4 agreements.

Article 2 of interim SO4, which the Decision ignores, explicitly prohibits exactly the type of price change which the Decision orders. Article 2 was approved in Decision 83-09-054 as part of PGandE's proposed interim SO4. It states that "*the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance* and shall not seek to or have a right to renegotiate such prices *for any reason.*" Further, "*Seller waives any and all rights to judicial or other relief from its . . . prices set forth in Appendices . . . E. . . .*" (Emphasis added.) Article 2 alone negates any construction of interim SO4 which would change the fixed firm capacity prices on the basis of implication.

The explicit language of Article 2 prevails over any contrary meaning Article 12 might otherwise imply. "It is clear that implication that would otherwise be reasonable should not be made when the contrary is indicated in clear and express words." *Clutts v. Southern Methodist Univ.*, 626 S.W. 2d 334, 336 (Tex. App. 1982), quoting Corbin, 3A *Corbin on Contracts* § 564 at 298 (1960). "No implied condition can be inserted as against the

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[1] Even if an inconsistency existed between Article 12 and Table E-2, the more specific provisions of Table E-2 would control the general Article 12 five-year provision. *See* Cal. Civ. Proc. § 1859. *Accord McNeely v. Claremont Management Co.*, 210 Cal.App.2d 749 (1962).

express terms of the contract." *Cousins Investment Co. v. Hastings Clothing Co.*, 45 Cal.App.2d 141, 148 (1941). The express Article 2 prohibition against any changes to the fixed contract prices makes untenable the Decision's implication of new escalated firm capacity prices.

2. Open Price Terms May Be Filled By A "Reasonable" Market Price

Because Table E-2 only provide fixed prices for firm capacity availability dates through 1987, a seller's delay in proving firm capacity past 1987 creates open price term for firm capacity payments. This result does not "cause an essential contract term to fail for indefiniteness," as the Decision states. Construing Table E-2 to provide fixed capacity prices only to sellers who begin firm capacity deliveries by the end of 1987, and "reasonable" market prices to sellers who delay past 1987, is the only interpretation that reconciles the firm capacity pricing terms with Article 2 and Article 12.

Payment of market prices to sellers who establish firm capacity availability dates after 1987 is not "wholly arbitrary," as the Decision states. Nor does it mean "making up" firm capacity prices. Construing a contract to provide payment of "reasonable" market prices when the parties failed to specify a price in a contract but intended to make an agreement is hornbook contract law. In such cases, a reasonable market price is the price due as a matter of law.

The California Uniform Commercial Code states that if a contract says nothing about price but the parties intended to make an agreement, "the price is a reasonable price at the time of delivery." Cal. Comm. Code § 2305(1). This provision is a specific application of the more general rule that "reasonable terms are implied by law to fill contract gaps. The Restatement (Second) of Contracts § 204 states:

> When the parties to a bargain sufficiently defined to be a contract have not agreed with respect to a term which is essential to a determination of their rights and duties, a term which is reasonable in the circumstances is supplied by the court.

The absence of specific intent by the parties that the "reasonable" term added by law be part of their contract is irrelevant. The "gap-filler provisions" of the UCC "have substantive effects. In other words, the contract . . . was made subject to this subdivision of the code and its requirements . . . were thereby added to the obligations of the parties under the contract." *Shea-Kaiser-Lockheed-Healy v. Department of Water & Power,* 73 Cal.App.3d 679, 689 (1977).

B. FERC Regulations And The Commission's Prior Decisions Do Not Support Implication Of New Fixed Firm Capacity Prices

1. The Commission's Earlier Decisions Do Not Justify Changes In Table E-2

As the Decision notes, interim SO4 was developed in 1983 through negotiations between the utilities, QF representatives and Commission staff. As it also notes, interim SO4 represents to some extent a cut-and-paste of then-existing standard offers. In particular, Table E-2 was adopted intact from the 1983 version of Standard Offer No. 2 ("SO2"). But the conclusion to be reached from interim SO4's origins is the opposite of that in the Decision, namely that Table E-2 should be extended by implication. Rather it shows that such an interpretation cannot be sustained.

PGandE incorporated the firm capacity prices that had been agreed to during the negotiating conference into proposed interim SO4, and presented the entire standard offer to the Commission for approval. The proposed interim SO4 presented in PGandE's application only contained fixed firm capacity prices for the years 1982 through 1987. Interim SO4 did not receive the benefit of any evidentiary hearings. The Commission did not have any record before it that would have allowed it to approve anything other than what the negotiators presented to it. *See* D.83-09-054, mimeo at pp.8, 11; D.85-04-075, mimeo at p.19.

The Commission's approval of interim SO4 was accordingly specifically limited to the contents of PGandE's application. Ordering paragraph 1 provides:

1. *Standard Offer #4, Payment Options #1 through #3, as proposed by the Pacific Gas and Electric Company* (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison), *shall be used by those utilities until further order* of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order. *Id.* (Emphasis added.)

Thus, Decision 83-09-054 approved nothing beyond the set of prices presented in PGandE's application. Those prices are identical to the prices contained in Table E-2 interim SO4. Both Decision 83-09-054 and PGandE's Third Amendment to A.82-04-044 (July 11, 1983) accurately state that the firm capacity prices provided in interim SO4 are levelized over the term of agreement. But neither even suggests that the interim SO4 price schedule would be available for a longer time or provide higher prices than the Table E-2 proposed by PGandE and approved by the Commission.

The Decision's reliance on Standard Offer No. 2 to justify extension of Table E-2 is misplaced. The SO2 firm capacity price schedule has been updated and extended, but only for prospective application to new contracts. The revisions have never applied to executed SO2 contracts. New escalated prices have never been implied for the period between the end of the SO2 fixed price schedule and its five-year deadline. Yet the Decision mandates such revisions in executed interim SO4 contracts. However, revisions to executed interim SO4 contracts are even more insupportable than changes to executed SO2 contracts. As Decision 84-08-035, mimeo, p.4 notes, interim SO4 was a "negotiated package." "A change in one term would require the reexamination of all other terms in the Standard Offer." Extension of Table E-2 without securing offsetting ratepayer benefits for the overpayments which are certain at least through the intial contract term tips interim SO4's economic balance entirely in the seller's favor.

2. The FERC Regulations Do Not Require Extension Of Table E-2

The FERC regulations do not compel the conclusion that Table E-2 must by implication be extended. Section 292.304(d)(2) states only that a QF have the option prior to the beginning of the "specified term" to receive payment based on either:

> (i) the avoided costs calculated at the time of delivery; or
> (ii) the avoided costs calculated at the time the obligation is incurred.
>
> 18 C.F.R. § 292.304(d)(2) (1986).

Table E-2 provides prices based on avoided costs calculated at the time the obligation was incurred for firm capacity availability dates through 1987. Whether a seller establishes a firm capacity availability date by the end of 1987 is entirely within the seller's control. A seller's inability to begin firm capacity deliveries in time to obtain the Table E-2 fixed prices results from the seller's delay, not from any deficiency in its agreement.

Under Article 12, the term of agreement for firm capacity sellers does not begin until the "firm capacity availability date." Interim SO4 therefore gives a seller the choice before the "specified term" begins of securing a fixed price under Table E-2 or delaying firm capacity deliveries past 1987 and receiving avoided cost calculated at the time of delivery. The absence of fixed firm capacity prices after 1987 in interim SO4 is fully consistent with the FERC regulations.

Indeed, implying an extension of the Table E-2 prices after 1987 would eliminate the seller's option to select a price calculated at the time of delivery. If the value of capacity had risen, not fallen, under the Decision's interpretation of Table E-2, the sellers could not have benefited.[2] Thus, far from compelling extension of

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[2] The possibility that capacity values would rise above the Table E-2 price was not as far fetched in 1983 as it may now seem. The firm capacity price schedule adopted in D.83-12-068, Table VI-4, mimeo at

Table E-2, the FERC regulations rule out any extension or escalation of the fixed firm capacity prices.

C. The Addition Of New, Escalated Fixed Prices To Executed Interim SO4 Contracts Exceeds The Commission's Authority And Violates PURPA

1. The Commission's Earlier Orders Prohibit The Addition Of New Prices To Executed SO4 Contracts

This Commission has repeatedly emphasized that no retroactive changes would or could be made to executed SO4 contracts. Decision 83-09-054 (Sept. 7, 1983) makes clear that a QF that selects interim SO4 is to be bound by its initial decision:

> Those who contract under interim Standard Offer #4 will not be subject to having terms or *prices* changed later, except as narrowly and specifically ordered by this decision. *Any changes* made to this standard offer in the future *will only apply to those contracting after such changes.*
>
> *Id.* at p.3 (Emphasis added.)

In rejecting a utility-proposed "regulatory authority" clause, the Commission stated that "[i]n ordering the clauses removed we recognize that we cannot order retroactive changes to interim Standard Offer #4 contracts but, given the restrictions placed on the use and availability of this negotiated standard offer, we are willing to commit to that loss in flexibility." (*Id.* at pp.39-40.) Thus, the Commission has barred even itself from making retroactive changes in interim SO4.

Accordingly, no matter what the Commission's continuing regulatory authority over interim SO4 might otherwise be, it legally disabled itself from exercising such authority with respect to interim SO4 on a retroactive basis. *See also* D.85-06-163, p.28 (June 21, 1985). As a consequence, the Commission lacks the authority to extend the availability of Table E-2 or add new escalated firm capacity prices to executed SO4 contracts. Ordering PGandE to amend its executed SO4 contracts to extend Table

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349 (Dec. 22, 1983) for use in SO2 contains even higher prices than Table E-2.

E-2 and to add new, escalated fixed prices was therefore legal error.

2. The Addition of New, Escalated Fixed Prices Violates PURPA

Section 210(b) of PURPA, 16 U.S.C. § 824a-3(b), decrees that the rate an electric utility pays for QF power shall not exceed the utility's avoided cost. Absent a waiver from FERC or, arguably, a state statute specifically authorizing payments in excess of avoided cost, avoided cost is the maximum rate the Commission may set.[3] The Commission has not obtained a waiver from FERC nor does there exist any California statute directing utilities to purchase QF power at prices in excess of avoided cost. In ordering PGandE to pay new firm capacity prices that the Commission has never determined to reflect avoided cost, the Decision violates PURPA.

As discussed earlier, the FERC rules require that avoided cost be calculated as of the time of delivery or as of the time of contract execution. 18 C.F.R. § 292.304(D) (1986). Ordering Paragraph 6 of the Decision orders PGandE to file amendments to Table E-2 to add new prices for years 1988, 1989 and 1990 using a discount rate of 15% and "combustion turbine cost escalation factors implicit in the table." The resulting figures for a thirty-year contract are $172/kw-year for 1988, $184/kw-year for 1989 and $196/kw-year for 1990. These prices do not represent avoided cost calculated as of the time of delivery. Indeed, they are dramatically in excess of current calculations of avoided cost. No Commission decision ever determined that the new escalated

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[3] *Compare Kansas City Power & Light Co. v. State Corp. Com'n,* 234 Kan. 1052, 676 P.2d 764, 765 (1984) (State Corporate Commission had no jurisdiction to order utility to purchase QF power at rate in excess of the utility's avoided cost) *with Consolidated Edison v. Public Serv. Comm'n,* 472 N.E. 2d 981, 63 N.Y.2d 424 (1984), *appeal dismissed, Consolidated Edison Co. v. Pub. Serv. Comm'n,* 105 S.Ct. 1831, 85 L.Ed.2d 132 (1985). (State statute specifically authorizing an above avoided-cost payment of 6 cents per kilowatt hour for QF energy, gave the Public Service Commission authority to order payments in excess of avoided cost).

prices the Decision ordered be added to interim SO4 contracts represented avoided cost. Accordingly, those prices violate PURPA.

Decision 82-12-120 required PGandE to use certain assumptions in calculating firm capacity prices. PGandE's 1983 SO2 contained the resulting prices. Those prices, which are identical to Table E-2, alone represent avoided cost "calculated at the time the obligation is incurred." The assumptions used to produce those numbers are not "avoided cost." The assumptions and methodology used to produce the Table E-2 prices were intended to be valid for only a limited period of time. *See* Decision 83-10-093, mimeo, p.12 (Oct. 19, 1983); Decision 84-03-092, mimeo, p.19 (March 21, 1984). In fact, they were superseded only four months later in PGandE's 1984 Test Year Rate Case, which approved new firm capacity prices. *See* Decision 83-12-068, Table VI-4, mimeo, p.349 (Dec. 22, 1983).

Calculating new firm capacity prices based on the outdated assumptions used to produce the Table E-2 numbers does not produce prices that meet either of the FERC rule's two-prong test. The resulting prices do not represent avoided cost calculated at the time sellers executed interim SO4 contracts and they certainly do not represent avoided cost calculated at the time of delivery. The Response of Independent Energy Producers Association (IEP) to Petitions For Modification Of Decision No. 83-09-054 Regarding Extension Of Firm Capacity Tables (dated Oct. 6, 1986) shows calculation of the new escalated firm capacity prices is not "ministerial." Instead, calculation of the new escalated firm capacity prices as ordered by the Decision requires making new assumption that were never approved by the Commission in any of its earlier decisions including Decision 82-12-120. IEP dismisses these new assumptions as trivial. Nonetheless, the need to make new asumptions in calculating the new escalated prices for years 1988-1990 establishes that in ordering PGandE to pay such prices, the Decision violates the FERC regulations and PURPA.

D. The Decision Substantially Increases The Cost Of QF Power To PGandE Customers And Gives A Windfall To "Gold-rush" QFs

It does not require a crystal ball to determine that the Decision will substantially increase the cost of QF power to PGandE and its customers. It is precisely because PGandE is, as the Decision notes, flush with capacity that the overpayment is virtually certain. PGandE's submittals in the OIR-2, Phase II compliance filing show PGandE has virtually no need for new capacity until the mid-1990's at the earliest. Overpayment during the early years is thus certain. *See also* Decision 86-10-044, mimeo, p.11 (Oct. 16, 1986). Only in the unlikely event that capacity values after 2000 substantially exceed both the 1982 forecast on which the capacity values in Table E-2 is based as well as current estimates will the early and certain overpayments be recouped.

The additional payments that the Decision mandates are substantial. PGandE previously calculated that if petitioners were paid the new escalated firm capacity prices for deliveries beginning in 1988 instead of PGandE's current estimate of avoided cost, the additional payments for petitioners' seventeen project would be almost $1.5 billion over the contract term ($401 million net present value), or about $56 million annually.[4] In limiting the price to that corresponding to petitioners' scheduled operation date, the Decision reduces the additional payments, but by less than 10 percent.

At least twelve projects representing about 418 MW of firm capacity which either have allocations under the interim solution or are located outside a transmission-constrained area specified scheduled operation dates after 1987 in their interim SO4 contracts. The difference between paying these sellers the escalated

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[4] *See* PGandE's Protest to Petitions for Modification and/or Clarification of Decisions 83-09-054 and 82-12-120 by Ultra Power, Inc., Thermal Energy Development Corp. and GWF Power Systems Co. dated September 12, 1986, Exhibit 2, p.1; and PGandE's Errata to Reply to Basic American Food's Petition for Consolidation and Expeditious Resolution of the Firm Capacity Issue into OIR2 Proceedings and Motion to Dismiss dated October 15, 1986.

prices ordered by the Decision and PGandE's current estimate of avoided cost is more than $1.2 billion over the contract terms ($335 million net present value) or more than $20 million annually. The value to PGandE of having QFs begin operation in 1990 instead of earlier is much less than the difference between the Table E-2 prices and the escalated prices, and nowhere near $1.2 billion.

Petitioners executed each of their seventeen interim SO4 contracts following the Commission's October 17, 1984 order suspending interim SO4 energy payment option 3 for QFs over 50 megawatts. Of the seventeen interim SO4 contracts, ten were executed by petitioners in April, 1985. All but one of the twelve projects with scheduled operation dates after 1987 have interim SO4 contracts executed after October 17, 1984; the exception was executed on October 15, 1984. Seven of the twelve were executed in April, 1985. Sellers apparently disregarded the immaturity of their project in their haste to obtain the favorable prices of an offer that many believed would soon be withdrawn. Sellers' haste should not entitle them to even higher fixed prices for even longer periods than their interim SO4 contracts now provide. Yet this result the Decision mandates.

IV
CONCLUSION

PGandE urges the Commission to grant rehearing of the Decision's extension of Table E-2 and addition of new escalated firm capacity prices for sellers who fail to begin firm capacity deliveries by the end of 1987. Article 2 and ordinary rules of contract intepretation bar implication of extended and escalated prices. The Decision's changes to prices in executed interim SO4 contracts exceed the Commission's authority and violate PURPA. It also substantially increases the high cost of power purchased under interim SO4 contracts. For these reasons, PGandE asks that rehearing of the Decision be granted and that sellers be held to the prices expressly provided in their interim SO4 contracts.

Respecfully submitted,

HOWARD V. GOLUB
LINDA L. AGERTER

By LINDA AGERTER
Linda Agerter
Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 17, 1986

APPENDIX K

Pacific Gas and Electric Company

Standard Offer #4
Power Purchase Agreement
for
Long-Term Energy
and Capacity

from

Qualifying Cogeneration
and
Small Power Production Facilities

September 1983

Long-Term Energy and Capacity
Power Purchase Agreement
Between

_____

and
Pacific Gas and Electric Company

_____ ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"), referred to collectively as "Parties" and individually as "Party", agree as follows:

Article 1 Qualifying Status

Seller warrants that, at the date of first power deliveries from Seller's *Facility*[1] and during the *term of agreement*, its *Facility* shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

Article 2 Commitment of Parties

The prices to be paid Seller for energy and/or capacity delivered pursuant to this Agreement have wholly or partly been fixed at the time of execution. Actual avoided costs at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this Agreement. Therefore, the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance and shall not seek to or have a right to renegotiate such prices for any reason. As part of its consideration for the benefit of fixing part or all of the energy and/or capacity prices under this Agreement, Seller waives any and all rights to judicial or other relief from its obligations and/or prices set forth in Appendices B, D, and E, or modification of any other term or provision for any reasons whatsoever.

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[1] Italics identifies those terms which are defined in Section A-1 of Appendix A.

This Agreement contains certain provisions which set forth methods of calculating damages to be paid to PGandE in the event Seller fails to fulfill certain performance obligations. The inclusion of such provisions is not intended to create any express or implied right in Seller to terminate this Agreement prior to the expiration of the *term of agreement*. Termination of this Agreement by Seller prior to its expiration date shall constitute a breach of this Agreement and the damages expressly set forth in this Agreement shall not constitute PGandE's sole remedy for such breach.

Article 3 Purchase of Power

(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of capacity and energy at the *voltage level* of ____ kV.

(b) Seller shall provide capacity and energy from its _____ kw *Facility* located at _____.
[Nameplate rating of generator(s)]

(c) The *scheduled operation date* of the *Facility* is _____.
[Date]

At the end of each calendar quarter Seller shall give written notice to PGandE of any change in the *scheduled operation date*.

(d) Seller shall limit the *Facility's* actual rate of delivery into the PGandE system to ____ kw.

(e) The primary energy source for the *Facility* is _____.

Article 4 Energy Price

PGandE shall pay Seller for its _____[1] under the energy payment option checked below:[2]

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[1] Insert either "*net energy output*" or "*surplus energy output*" to show the energy sale option selected by Seller.

[2] Option 2 is not available to oil or gas-fired cogenerators.

Energy Payment Option 1—Forecasted Energy Prices

During the *fixed price period*, Seller shall be paid for energy delivered at prices equal to ____[3] percent of the prices set forth in Table B-1, Appendix B, plus ____[4] percent of PGandE's *full short-run avoided operating costs.*

For the remaining years of the *term of agreement*, Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

If Seller's *Facility* is not an oil or gas-fired cogeneration facility, Seller may convert from Energy Payment Option 1 to Energy Payment Option 2 and be subject to the conditions therein, provided that Seller shall not change the percentage of energy prices to be based on PGandE's *full short-run avoided operating costs.* Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

Energy Payment Option 2—Levelized Energy Prices

During the *fixed price period,* Seller shall be paid for energy delivered at prices equal to ____[5] percent of the levelized energy prices set forth in Table B-2, Appendix B for the year in which energy deliveries begin and *term of agreement*, plus ____[6] percent of PGandE's *full short-run avoided operating costs.* During the *fixed price period*, Seller shall be subject to the conditions and terms set forth in Appendix B, Energy Payment Option 2.

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[3] Insert either 0, 20, 40, 60, 80, or 100, at Seller's option. If Seller's *Facility* is an oil or gas-fired cogeneration facility, either 0 or 20 must be inserted

[4] Insert the difference between 100 and the percentage selected under footnote 2 above.

[5] Insert either 20, 40, 60, 80, or 100, at Seller's option.

[6] Insert the difference between 100 and the percentage selected under footnote 4 above.

For the remaining years of the *term of agreement*, Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

Seller may convert from Energy Payment Option 2 to Energy Payment Option 1, provided that Seller shall not change the percentage of energy prices to be based on PGandE's *full short-run avoided operating costs.* Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

Energy Payment Option 3—Incremental Energy Rate

Beginning with the date of initial energy deliveries and continuing until _____,[7] Seller shall be paid monthly for energy delivered at prices equal to PGandE's *full short-run avoided operating costs,* provided that adjustments shall be made annually to the extent set forth in Appendix B, Energy Payment Option 3.

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[7] Specified by Seller. Must be December 31, 1998 or prior.

The Incremental Energy Rate Band Widths specified by Seller in Table I below shall be used in determining the annual adjustment, if any.

TABLE I

Year	Incremental Energy Rate Band Widths (must be multiples of 100 or zero)
1984	
1985	
1986	
1987	
1988	
1989	
1990	
1991	
1992	
1993	
1994	
1995	
1996	
1997	
1998	

After , Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

Article 5 Capacity Election and Capacity Price

Seller may elect to deliver either *firm capacity* or *as-delivered capacity,* and Seller's election is indicated below:

Firm capacity—____ kW for ____ years from the *firm capacity availability date* with payment determined in accordance with Appendix E. Except for hydroelectric facilities, PGandE shall pay Seller for capacity delivered in excess of *firm capacity* on an *as-delivered capacity* basis in accordance with As-Delivered Capacity Payment Option __ set forth in Appendix D.

OR

As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option __ set forth in Appendix D.

Article 6 Loss Adjustment Factors

Capacity Loss Adjustment Factors shall be as shown in Appendix D and Appendix E, dependent upon Seller's capacity election set forth in Article 5 of this Agreement.

Energy Loss Adjustment Factors shall be considered as unity for all energy payments related to Energy Payment Options 1 and 2 set forth in Appendix B for the entire *fixed price period* of this Agreement, except for the percentage of payments that Seller elected in Article 4 to have calculated based on PGandE's *full short-run avoided operating costs.* Energy Loss Adjustment Factors for all payments related to PGandE's *full short-term avoided operating* costs are subject to *CPUC* rulings for the entire *term of agreement.*

Article 7 Curtailment

Seller has two options regarding possible curtailment by PGandE of Seller's deliveries, and Seller's selection is indicated below:

Curtailment Option A—Hydro Spill and Negative Avoided Cost

Curtailment Option B—Adjusted Price Period

The two options are described in Appendix C.

Article 8 Retroactive Application of CPUC Orders

Pursuant to Ordering Paragraph 1(f) of *CPUC* Decision No. 83-09-054 (September 7, 1983), after the effective date of the *CPUC's* Application 82-03-26 decision relating to 1) line loss factors; 2) interconnection provisions involving future lines and system upgrades; and 3) insurance, Seller has the option to retain

the relevant terms of this Agreement or have the results of that decision incorporated into this Agreement. To retain the terms herein, Seller shall provide written notice to PGandE within 30 days after the effective date of the relevant *CPUC* decision on Application 82-03-26. Failure to provide such notice will result in the amendment of this Agreement to comply with that decision.

As soon as practicable following the issuance of a decision in Application 82-03-26, PGandE shall notify Seller of the effective date thereof and its results.

Article 9 Notices

All written notices shall be directed as follows:

To PGandE: Pacific Gas and Electric Company
Attention: Vice President—Electric Operations
77 Beale Street
San Francisco, CA 94106

To Seller: _____
_____
_____
_____
_____

Article 10 Designated Switching Center

The ***designated PGandE switching center*** shall be, unless changed by PGandE:

_____
(Name)

_____
(Location)

_____
(Phone Number)

Article 11 Terms and Conditions

This Agreement includes the following appendices which are attached and incorporated by reference:

Appendix A—GENERAL TERMS AND CONDITIONS
Appendix B—ENERGY PAYMENT OPTIONS
Appendix C—CURTAILMENT OPTIONS
Appendix D—AS-DELIVERED CAPACITY
Appendix E—FIRM CAPACITY

Article 12 Term of Agreement

This Agreement shall be binding upon execution and remain in effect for _____ years[1] from the date of initial deliveries; provided, however, that it shall terminate if energy deliveries do not start within five years of the effective date.

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[1] The minimum contract term is 15 years and the maximum contract term is 30 years.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and it is effective as of the last date set forth below.

_____

(SELLER)

BY: _____

_____

(Type Name)

TITLE: _____

DATE SIGNED: _____

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

_____

(Type Name)

TITLE: _____

DATE SIGNED: _____

Appendix A

General Terms and Conditions

A-1 Definitions

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Adjusted firm capacity price—The $/kW-year purchase price for *firm capacity* from Table E-2, Appendix E for the period of Seller's actual performance.

As-delivered capacity—Capacity delivered to PGandE in excess of *firm capacity* or in lieu of a *firm capacity* commitment.

CPUC—The Public Utilities Commission of the State of California.

Current firm capacity price—The $/kW-year capacity price from PGandE's *firm capacity price schedule* effective at the time PGandE derates the *firm capacity* pursuant to Section E-4(b), Appendix E or Seller terminates performance under this Agreement, for a term equal to the period from the date of deration or termination to the end of the *term of agreement*.

Designated PGandE switching center—That switching center or other PGandE installation identified in Article 10.

Facility—That generation apparatus described in Article 3 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity—That capacity, if any, identified as firm in Article 5 except as otherwise changed as provided herein.

Firm capacity availability date—The day following the day during which all features and equipment of the *Facility* are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver *firm capacity* continuously into PGandE's system as provided in this Agreement.

Firm capacity price—The price for *firm capacity* applicable for the *firm capacity availability date* and the number of years of *firm capacity* delivery from either the *firm capacity price schedule,* Table E-2, Appendix E, or the successor to Table E-2 in effect on the *firm capacity availability date,* whichever is higher.

Firm capacity price schedule—The periodically published schedule of the $/kW-year prices that PGandE offers to pay for *firm capacity.* See Table E-2, Appendix E.

Fixed price period—The period during which forecasted or levelized energy prices, and/or forecasted *as-delivered capacity* prices, are in effect; defined as the first five years of the *term of agreement* if the *term of agreement* is 15 or 16 years; the first six years of the *term of agreement* if the *term of agreement* is 17, 18, or 19 years; or the first ten years of the *term of agreement* if the *term of agreement* is anywhere from 20 through 30 years.

Forced outage—Any outage resulting from a design defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the *Facility.*

Full short-run avoided operating costs—*CPUC*-approved costs which are the basis of PGandE's published energy prices. PGandE's current energy price calculation is shown in Table B-5, Appendix B. PGandE's published off-peak hours' prices shall be adjusted, as appropriate, if Seller has selected Curtailment Option B.

Interconnection facilities—All means required and apparatus installed to interconnect and deliver power from the *Facility* to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the *Facility,* and (2) the *Facility* from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. *Interconnection facilities* also include any necessary

additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the *Facility* to the PGandE system.

Net energy output—The *Facility's* gross output in kilowatt-hours less *station use* and transformation and transmission losses to the point of delivery into the PGandE system.

Prudent electrical practices—Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled operation date—The day specified in Article 3(c) when the *Facility* is, by Seller's estimate, expected to produce energy that will be available for delivery to PGandE.

Special facilities—Those parts of the *interconnection facilities* furnished by PGandE at Seller's request, metering and data processing equipment, and those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the *Facility* as provided in this Agreement. All *special facilities* shall be furnished at Seller's expense pursuant to PGandE's electric Rule No. 21 by a separate agreement.

Station use—Energy used to operate the *Facility's* auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output—The *Facility's* group output, in kilowatt-hours, less *station use,* and any other use by Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement—The number of years this Agreement will remain in effect from the date of initial energy deliveries, as provided in Article 12.

Voltage level—The voltage at which the *Facility* interconnects with the PGandE system, measured at the point of delivery.

A-2 Construction

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements, including adequate and continuing access rights on property of Seller, to install, operate, maintain, replace, and remove the *special facilities.* Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shall reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the *Facility* at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

(a) Seller shall design, construct, install, own, operate, and maintain all *interconnection facilities,* except *special facilities,* to the point of interconnection with the PGandE system as required for PGandE to recieve capacity and energy from the *Facility.* The Facility and *interconnection facilities* shall meet all requirements of applicable codes and all standards of *prudent electrical practices* and shall be managed in a safe and prudent manner.

(b) Seller shall submit to PGandE all specifications for the *interconnection facilities* (except *special facilities*) and, at PGandE's option, the *Facility,* for review and written

acceptance prior to their release for construction purposes. PGandE's review and acceptance of these specifications shall not be construed as confirming or endorsing the design or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the *interconnection facilities* as may be reasonably required by PGandE to meet changing requirements of the PGandE system.

(c) In the event it is necessary for PGandE to install *interconnection facilities* for the purpose of this Agreement, they shall be installed as *special facilities.*

A-2.3 Meter Installation

(a) PGandE shall specify, provide, install, own, operate, and maintain as *special facilities* all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.

(b) Seller shall provide, construct, install, own and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

A-3 Operation

A-3.1 Inspection and Approval

Seller shall not operate the *Facility* in parallel with PGandE's system until an authorized PGandE representative has inspected the *interconnection facilities,* and PGandE has given written approval to begin parallel operation.

A-3.2 *Facility* Operation and Maintenance

Seller shall operate and maintain its *Facility* according to *prudent electrical practices,* applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the *Facility* at the power factor or voltage levels prescribed by PGandE's system dispatcher or designated representative if Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-3.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors contact PGandE's existing system or at such other point as the Parties may agree in writing.

A-3.4 Operating Communications

(a) Seller shall maintain operating communications with the *designated PGandE switching center.* The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors and daily capacity and generation reports.

(b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant event related to the operation of the *Facility.*

(c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location with the *Facility* agreed to by both parties.

(d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the *designated PGandE switching center,* twice a day at agreed upon times for the current day's operation, the

hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.

(e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the *designated PGandE switching center.*

A-3.5 Meter Testing and Inspection

(a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.

(b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-3.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for—(1) the actual period during which inaccurate measurements were made, if the period can be deter-

mined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-4 Payment

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period (1) a statement showing the energy and capacity delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in payment of said amount. If within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-5 Adjustments of Payments

(a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-3.6 to recompute the amount due from PGandE to Seller for the capacity and energy delivered under this Agreement during the period of inaccuracy.

(b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-6 Access to Records

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs of the *Facility*.

A-7 Interruption of Deliveries

PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace,

remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of PGandE system emergencies, forced outages, force majeure, or compliance with *prudent electrical practices;* provided that PGandE shall not interrupt deliveries pursuant to this section in order to take advantage, or make purchases, of less expensive energy elsewhere. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

A-8 Force Majeure

(2) The term force majeure as used herein means unforeseeable causes, other than *forced outages,* beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure, including but not limited to, acts of God, labor disputes, sudden actions of the elements, and actions by federal, state, municipal, or any other government agency.

(b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:

(1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,

(3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts,

lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty),

(4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and

(5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section E-2(c), Appendix E.

A-9 Indemnity

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence, or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-10 Liability; Dedication

(a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.

(b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities,

and such other Party shall not be liable for any such damages so caused.

(c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-11 Several Obligations

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust of partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-12 Non-Waiver

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-13 Assignment

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-14 Captions

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-15 Choice of Laws

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-16 Governmental Jurisdiction and Authorization

Seller warrants that the *Facility* and *interconnection facilities,* except special facilities, shall at all times conform to all applicable laws and regulations, and Seller shall obtain any governmental authorizations and permits required for the construction and operation thereof. If at any time Seller does not hold such authorizations and permits PGandE may refuse to accept deliveries of power hereunder.

A-17 Notices

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section E-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 9 of this Agreement. Changes in such designation may be made by notice similarly given.

A-18 Insurance

A-18.1 Workers' Compensation

Seller shall furnish PGandE a certificate of workers' compensation or self-insurance indicating compliance with the Labor Code

of California, including Employer's Liability insurance with a minimum of $2,000,000 for injury or death of any one person. This certificate shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.2 Comprehensive General and Comprehensive automobile Liability Coverage

(a) Seller shall maintain during the performance hereof, Comprehensive General Liability and Comprehensive Automobile Liability of not less than $3,000,000 combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence

(b) Comprehensive General Liability shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations. Comprehensive Automobile Liability shall include coverage for Owned, Hired, and Non-Owned automobiles.

(c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.3 Additional Insurance Provisions

(a) Evidence of coverage described above in Sections A-18.1 and A-18.2 shall state that coverage provided is

primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.

(b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

(c) Seller shall furnish the required certificates and endorsements to PGandE prior to the date construction of the *Facility* begins or the effective date of this Agreement, whichever is later.

(d) All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager—Insurance Department
77 Beale Street
San Francisco, CA 94106

APPENDIX B
ENERGY PAYMENT OPTIONS

Energy Payment Option 1—Forecasted Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during each year of the *fixed price period* shall include the appropriate prices for such year in Table B-1, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the forecasted off-peak hours' energy prices listed in Table B-1 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B.

TABLE B-1
Forecasted Energy Price Schedule

Year of Energy Deliveries	Forecasted Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.16
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 2—Levelized Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the *fixed price period* shall include the appropriate prices set forth in Table B-2 for the year in which energy deliveries begin and *term of agreement*, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the levelized off-peak hours' energy prices listed in Table B-2 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B. The discount specified in (c)(vi) below, if applicable, will be applied to the energy payments during the *fixed price period.*

During the *fixed price period*, Seller shall be subject to the following conditions and terms:

(a) Minimum Damages

The Parties agree that the levelized energy prices which PGandE pays Seller for the energy which Seller delivers to PGandE is based on the agreed value to PGandE of Seller's energy deliveries during the entire *fixed price period.* In the event PGandE does not receive such full performance by reason of a termination, Seller shall pay PGandE an amount based on the difference between the net present values, at the time of termination, of the payments Seller would receive at the forecasted energy prices in Table B-1 and the payments Seller would receive at the levelized energy prices, for the remaining years of the *fixed price period.* This amount shall be calculated by assuming that Seller continued to generate for the remaining years of the *fixed price period* at a level equal to the average annual energy generation during the period of performance, and by applying the weighted annual average levelized price applicable to Seller's *Facility* and the weighted annual average forecasted energy prices in Table B-1 for the remaining years of the *fixed price period.* The following formula shall be used to make this calculation:

$$P = \sum_{n=1}^{Y} \frac{(F_n)\ (A)\ (W)}{(1.15)^n} - \sum_{n=1}^{Y} \frac{(L)\ (A)\ (W)}{(1.15)^n}$$

where:

P = amount due PGandE

Y = number of years remaining in the *fixed price period*

F_n = Weighted annual average forecasted energy price in the n^{th} year after the breach, failure to perform, or expiration of security, as shown in Table B-1 for the corresponding calendar year

L = weighted annual average levelized energy price applicable to Seller's *Facility*

A = average annual energy generation by Seller during the period of performance

n = summation index; refers to the n^{th} year following termination

W = percent of Seller's energy payments based on the levelized energy prices, as specified in Article 4

(b) Performance Requirements

Seller shall operate and maintain the *Facility* in accordance with *prudent electrical practices* in order to maximize the likelihood that the *Facility's* output as delivered to PGandE during the part of the *fixed price period* when the levelized price is below the forecasted price ("last part") shall equal or exceed 70% of the *Facility's* output during the part of the *fixed price period* when the levelized price is above the forecasted price ("first part"). In the event that the *Facility's* output during any year or series of years in the last part of the *fixed price period* is less than 70% of the average annual production during the first part of the *fixed price period,* PGandE may, at its discretion (taking into consideration events occurring during such year or series of years such as curtailment by PGandE, Seller's choice not to operate during adjusted price periods, or scheduled maintenance including major overhauls, and the probability that Seller's future performance will be adequate), either request payment from Seller or immediately draw, on the security posted, up to the amount equal to

$$P \times \frac{A\text{-}B}{A,}$$ where:

P and A are as defined in Section (a) above.

B = Seller's average annual energy generation during the year or series of years in which the 70% performance requirement was not met.

PGandE shall *not* request payment from Seller or draw on the security posted if the *Facility's* output during the last part of the fixed price period falls below 70% of the average annual energy generation during the first part of the *fixed price period* solely because of force majeure as defined in Section A-8, Appendix A or a lack of or limited availability of the primary energy resource of the *Facility,* if such energy resource is wind, water, or sunlight.

(c) Security

(1) As security for amounts which Seller may be obligated to pay PGandE pursuant to Sections (a) and (b) above, Seller shall provide and maintain one or more of the following in an amount as described in Section (c)(2) below.

(i) An irrevocable bank letter of credit delivered to and in favor of PGandE with terms acceptable to PGandE.

(ii) A payment bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(iii) Fully paid up, noncancellable Project Failure Insurance made payable to PGandE with terms of such policy(ies) acceptable to PGandE.

(iv) A performance bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(v) A corporate guarantee of payment to PGandE which PGandE deems, in its sole discretion, to provide at least the same quality of security as subsections (i) through (iv) above.

(vi) Other forms of security which PGandE does not deem to be equivalent security to those listed in subsections (i) through (v) above, and which PGandE, in its sole discretion, deems adequate. Such other forms of security may include, for example, a corporate guarantee or a lien, mortgage or deed of trust on the *Facility* or land upon which it is located. A 1.5% discount will be applied against the levelized energy price portion of PGandE's payments to Seller during the *fixed price period* if this type of security is provided.

(2) (i) Commencing 90 days prior to the *scheduled operation date* and continuing until December 1 of the following calendar year, security as described in Section (c)(1) above shall be in place in an amount calculated in accordance with the formula set forth in Section (a) above, assuming Seller delivered energy through the end of the following calendar year and then terminated this Agreement. For purposes of determining the required amount of security, it shall be assumed that Seller's deliveries through the end of the following calendar year would equal $R \times C \times H$, where:

R = nameplate rating, in kWh, of the *Facility*

C = estimated capacity factor of the *Facility,* which shall be established by mutual agreement of the Parties at the time of execution of this Agreement

H = number of hours from the *scheduled operation date* through the end of the following calendar year

(ii) In the second calendar year of operation and each year thereafter until the end of the *fixed price period*, from December 1 through December 1 of the following year, security shall be in an amount calculated by the formula set forth in Section (a) above assuming Seller continued to deliver energy in each month through the end of the following calendar year, at a level equal to the average monthly energy deliveries to date, and then terminated this Agreement.

(3) Security must be maintained throughout the *fixed price period* as specified above. Any security with a fixed expiration date must be renewed by Seller prior to that date. If such security is not renewed at least 30 days prior to its expiration, PGandE may, at its discretion, either request payment from Seller or immediately draw on the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above.

(4) If, at any time during the *fixed price period*, PGandE believes Seller is in material breach of this Agreement, PGandE shall so notify Seller in writing and Seller must remedy such breach within a reasonable period of time. If Seller does not so remedy, PGandE may, at its discretion, either request payment from Seller or immediately draw upon the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above, provided that if during Seller's period to remedy, Seller disputes PGandE's conclusion that Seller is in material breach, and PGandE elects to draw upon the security, the amount drawn upon by PGandE shall be deposited in an interest earning escrow account and held in such account until the dispute is resolved in accordance with Section (c)(5) below.

(5) Upon the written request of either Party, any controversy or dispute between the Parties concerning Section (c)(4) above shall be subject to arbitration in accordance with the provisions of the California Arbitration Act, Sections 1280-1294.2 of the California Code of Civil Procedure except as provided otherwise in this section. Either Party may demand arbitration by first giving written notice of the existence of a dispute and then within 30 days of such notice giving a second written notice of the demand for arbitration.

Within ten days after receipt of the demand for arbiration, each Party shall appoint one person, who shall not be an employee of either Party, to hear and determine the dispute. After both arbitrators have been appointed, they shall within five (5) days select a third arbitrator.

The arbitration hearing shall take place in San Francisco, California, within 30 days of the appointment of the arbitrators, at such time and place as they select. The arbitrators shall give written notice of the time of the hearing to both Parties at least ten days prior to the hearing. The arbitrators shall not be authorized to alter, extend, or modify the terms of this Agreement. At the hearing, each Party shall submit a proposed written decision, and any relevant evidence may be presented. The decision of the arbitrators must consist of selection of one of the two proposed decisions, in its entirety.

The decision of any two arbitrators shall be binding and conclusive as to disputes relating to Section (c)(4) only. Upon determining the matter, the arbitrators shall promptly execute and acknowledge their decision and deliver a copy to each Party. A judgment confirming the award may be rendered by any superior court having jurisdiction. Each Party shall bear its own arbitration costs and expenses, including the cost of the arbitrator it selected, and the costs and expenses of the third arbitrator shall be divided equally between both Parties, except as provided otherwise elsewhere in this Agreement.

Pending resolution of any controversy or dispute hereunder, performance by each Party shall continue so as to maintain the status quo prior to notice of such controversy or dispute. Resolution of the controversy or dispute shall include payment of any interest accrued in the escrow account.

TABLE B-2

Levelized Energy Price Schedule

For a *term of agreement* of 15-16 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.76	5.50	5.31	5.85	5.71	5.58	5.57
1984	6.06	5.78	5.58	6.14	6.00	5.86	5.85
1985	6.41	6.11	5.91	6.50	6.35	6.20	6.19
1986	6.85	6.54	6.32	6.95	6.79	6.63	6.62
1987	7.37	7.03	6.79	7.47	7.30	7.13	7.12
1988	7.96	7.60	7.34	8.07	7.89	7.70	7.69

For a *term of agreement* of 17-19 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.90	5.63	5.44	5.98	5.84	5.71	5.70
1984	6.23	5.95	5.74	6.32	6.18	6.03	6.02
1985	6.60	6.30	6.08	6.69	6.53	6.38	6.37
1986	7.06	6.73	6.51	7.16	7.00	6.83	6.82
1987	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1988	8.21	7.83	7.57	8.32	8.13	7.94	7.93

* These prices are differentiated by the time periods as defined in Table B-4.

For a *term of agreement* of 20-30 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	6.49	6.20	5.98	6.58	6.43	6.28	6.27
1984	6.90	6.58	6.35	6.99	6.83	6.67	6.66
1985	7.34	7.00	6.76	7.44	7.27	7.10	7.09
1986	7.88	7.51	7.26	7.99	7.81	7.62	7.61
1987	8.49	8.10	7.82	8.61	8.41	8.21	8.20
1988	9.16	8.74	8.44	9.29	9.08	8.86	8.85

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 3—Incremental Energy Rate

During the period specified in Article 4, annual adjustments to Seller's energy payments shall be made as described below.

At the end of each calendar year, the Derived Incremental Energy Rate (with units expressed in Btu/kWh) will be calculated as follows:

$$\text{Derived Incremental Energy Rate (DIER)} = \frac{B}{A \times C}$$

where:

A = the total kWh delivered by Seller during the calendar year, excluding any kWh delivered when Seller was asked to curtail deliveries under Curtailment Option A *or* when Seller was asked to take adjusted prices under Curtailment Option B

B = the total dollars paid for the energy described for A above

C = the weighted average price paid during the calendar year by PGandE's Electric Department for oil and natural gas for PGandE's fossil steam plants, expressed in S/Btu on a gas Btu basis

If the DIER is between the upper and lower Incremental Energy Rate Bounds specified for that year in Table B-3 for the curtailment option selected by Seller, no additional payment is due either Party.

If the DIER is below the lower Incremental Energy Rate Bound, PGandE shall pay Seller an amount calculated as follows:

$$P_S = (\text{Lower Incremental Energy Rate Bound} - \text{DIER})\ (A)\ (C)$$

where:

P_S = additional payment due Seller

DIER = Derived Incremental Energy Rate

PGandE shall add this payment to the first payment made to Seller following the calculation.

If the DIER is above the upper Incremental Energy Rate Bound, Seller shall pay PGandE an amount calculated as follows:

$$P_B = (\text{DIER} - \text{Upper Incremental Energy Rate Bound}) \quad (A)\ (C)$$

where:

P_B = amount due PGandE
DIER = Derived Incremental Energy Rate

This amount shall be deducted from the first payment made to Seller following the calculation. If there is any remaining amount due PGandE, PGandE may, at its option, invoice Seller with such payment due within 30 days or deduct this amount from future payments due Seller.

TABLE B-3

Forecasted Incremental Energy Rates and Incremental Energy Rate Bounds

Curtailment Option A:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column (b)]
1984	9,000			
1985	9,050			
1986	8,840			
1987	8,850			
1988	8,960			
1989	8,820			
1990	8,540			
1991	8,540			
1992	8,540			
1993	8,540			
1994	8,540			
1995	8,540			
1996	8,540			
1997	8,540			
1998	8,540			

TABLE B-3—(Continued)

Forecasted Incremental Energy Rates and Incremental Energy Rate Bounds

Curtailment Option B:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column (b)]
1984	9,440			
1985	9,500			
1986	9,280			
1987	9,290			
1988	9,400			
1989	9,270			
1990	8,970			
1991	8,970			
1992	8,970			
1993	8,970			
1994	8,970			
1995	8,970			
1996	8,970			
1997	8,970			
1998	8,970			

TABLE B-4[1]

	Monday through Friday[2]	Saturdays[2]	Sundays and Holidays
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

[1] This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

[2] Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving , and Christmas as said days are specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a).

Table B-5

Energy Prices Effective
August 1-October 31, 1983

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during August, September, and October 1983 are as follows:

Time Period	Incremental Heat Rate(1) (a)	Cost of Energy(2) (b)	Energy Purchase Price(3)(4) (c) = (a) × (b)
May 1—September 30 (Period A)			
Time of Delivery Basis:			
On Peak	11,447 Btu/kWh	$5.3948/6 Btu	$0.06175/kWh
Partial-Peak	10,919	5.3948	0.05891
Off-Peak	10,549	5.3948	0.05691
Seasonal Average (Period A)	10,821	5,3948	0.05838
October 1—April 30 (Period B)			
Time of Delivery Basis:			
On-Peak	11,605 Btu/kWh	$5,3948/6 Btu	$0.06261/kWh
Partial-Peak	11.341	5.3948	0.06118
Off-Peak	11,067	5.3948	0.05970
Seasonal Average (Period B)	11,231	5.3948	0.06059

(1) Incremental heat rates are derived from marginal energy costs (including variable operating and maintenance expense) adopted by *CPUC* Decision No. 93887. They are adjusted to reflect the use of natural gas as the incremental fuel.

(2) Cost of natural gas under PGandE Gas Schedule No. G-55 effective 7/1/83 per Advice No. 1225-G (Supplemental), Resolution No. 2545.

(3) Energy Purchase Price = Incremental Heat Rate × Cost of Energy.

(4) This figure excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the *CPUC* in the future.

APPENDIX C

CURTAILMENT OPTIONS

Seller has two options regarding curtailment of energy deliveries and Seller has made its selection in Article 6. The two options are as follows:

CURTAILMENT OPTION A—HYDRO SPILL AND NEGATIVE AVOIDED COST

(a) In anticipation of a period of hydro spill conditions, as defined by the *CPUC*, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF\text{-}S}{AQF} \times PP \quad (\geq 0)$$

where:

AQF= Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period.

(b) PGandE shall not be obligated to accept or pay for and may require Seller with a *Facility* with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy

during periods when PGandE would incur negative avoided costs (as defined by the *CPUC*) due to continued acceptance of energy deliveries under this Agreement.

Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

(c) Before interrupting or reducing deliveries under subsection (b), above, and before invoking hydro savings prices under subsection (a), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.

(d) If Seller is selling *net energy output* to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (a) or when PGandE curtails deliveries of energy pursuant to subsection (b), Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE. If Seller is selling *surplus energy output* to PGandE, subsections (a) or (b) shall only apply to the *surplus energy output* being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

CURTAILMENT OPTION B—ADJUSTED PRICE PERIOD

(a) In each calendar year, the price which PGandE is obligated to pay Seller for energy deliveries during 1,000 off-peak hours (as defined in Table B-4, Appendix B) may be adjusted to a price equal to, but not in excess of, PGandE's available alternative source. This adjusted price shall be effective under any of the following conditions:

(i) when PGandE's energy source at the margin is not a PGandE oil- or gas-fueled plant, and PGandE can replace Seller's energy with energy from this source at a cost less than the price paid to Seller;

(ii) when PGandE would incur negative avoided costs (as defined by the *CPUC*) due to continued acceptance of energy deliveries under this Agreement; or

(iii) when PGandE is experiencing minimum system operations.

During any of the conditions described above the adjusted price may be zero.

(b) Whenever possible, PGandE shall give Seller reasonable notice of any price adjustment for energy deliveries and its probable duration.

(c) If Seller is selling *net energy output* to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the adjusted price, Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE.

(d) After Seller receives notice of the probable duration of the period during which the adjusted price will be paid, Seller may elect to perform maintenance during such period and so inform the PGandE employee in charge at the *designated PGandE switching center* prior to the time when the adjusted price period is expected to begin. If Seller makes such election, the number of off-peak hours of probable duration quoted in PGandE's notice to Seller shall be applied to the 1,000 hour calendar year limitation set forth in this section. After an election to do maintenance, if Seller makes any deliveries of energy during the quoted probable duration period, Seller shall be paid the adjusted price quoted in its notice from PGandE without regard to any subsequent changes on the PGandE system which may alter the adjusted price or shorten the actual duration of the condition.

APPENDIX D

AS-DELIVERED-CAPACITY

D-1 AS-DELIVERED CAPACITY PAYMENT OPTIONS

Seller has two options for *as-delivered capacity* payments and Seller has made its selection in Article 5. The two options are as follows:

AS-DELIVERED CAPACITY PAYMENT OPTION 1

PGandE shall pay Seller for *as-delivered capacity* at prices authorized from time to time by the *CPUC*. The *as-delivered capacity* prices in effect on the date of execution are calculated as shown in Exhibit D-1, with a shortage cost of $70 per kilowatt-year.

AS-DELIVERED CAPACITY PAYMENT OPTION 2

During the *fixed price period,* the *as-delivered capacity* prices will be calculated in accordance with Exhibit D-1 and the forecasted shortage costs in Table D-2.

For the remaining years of the *term of agreement,* PGandE shall pay Seller for *as-delivered capacity* at the higher of:

(i) Prices authorized from time to time by the *CPUC;*

(ii) the *as-delivered capacity* prices that were paid Seller in the last year of the *fixed price period;* or

(iii) the *as-delivered capacity* prices in effect in the first year following the end of the *fixed price period,* provided that the annualized shortage cost from which these prices are derived does not exceed the annualized value of a gas turbine.

D-2 AS-DELIVERED CAPACITY IN EXCESS OF FIRM CAPACITY

The amount of capacity delivered in excess of *firm capacity* will be considered *as-delivered capacity*. This *as-delivered capacity* is

based on the total kilowatt-hours delivered each month during all on-peak, partial-peak and off-peak hours excluding any energy associated with generation levels equal to or less than the *firm capacity*.

Seller has the two options listed in Section D-1 for payment for such *as-delivered capacity*. Seller has made its selection in Article 5.

EXHIBIT D-1

The *as-delivered capacity* price (in cents per kW-hr) for power delivered by the *Facility* is the product of three factors:

(a) The shortage cost in each year the *Facility* is operating.

(b) A capacity loss adjustment factor which provides for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote[1] Facilities are presented in Table D-1(a). Capacity loss adjustment factors for remote Facilities shall be calculated individually.

(c) An allocation factor which accounts for the different values of *as-delivered capacity* in different time periods and converts dollars per kW-year to cents per kWh. The current allocation factors are presented in Table D-1(b). The time periods to which they apply are shown in Table B-4, Appendix B. The allocation factors are subject to change from time to time.

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[1] As defined by the *CPUC*.

TABLE D-1(a)
Capacity Loss Adjustment Factors For Non-Remote(1) Facilities

Voltage Level	Loss Adjustment Factor
Transmission	.989
Distribution	.991

If the *Facility* is remote, the capacity loss adjustment factor is _____.(2)

TABLE D-1(b)
Allocation Factors For As-Delivered Capacity(3)

	Peak (¢-yr/$-hr)	Partial Peak (¢-yr/$-hr)	Off-Peak (¢-yr/$-hr)
Seasonal Period A	.09982	.01635	.00000
Seasonal Period B	.02023	.00306	.00001

TABLE D-2
Forecasted Shortage Cost Schedule

Year	Forecast Shortage Cost, $/kW-Yr
1983	70
1984	76
1985	81
1986	88
1987	95
1988	102
1989	110
1990	118
1991	126
1992	135
1993	144
1994	154
1995	164
1996	176
1997	188

(1) As defined by the *CPUC*. The capacity loss adjustment factors for remote Facilities are determined individually.

(2) Determined individually.

(3) The units for the allocation factor, ¢-yr/$-hr, are derived from the conversion of $/kW-yr into ¢/kWh as follows:

$$\frac{¢/kWh}{\$/kW\text{-}yr} = \frac{¢/kW\text{-}hr}{\$/kW\text{-}yr} = \frac{¢\text{-}yr}{\$\text{-}hr}$$

The allocation factors are subject to change from time to time.

APPENDIX E
FIRM CAPACITY

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APPENDIX E

FIRM CAPACITY

E-1 GENERAL

This Appendix E estabished conditions and prices under which PG&E shall pay for *firm capacity*.

PG&E's obligation to pay for *firm capacity* shall begin on the *firm capacity availability date*. The *firm capacity price* shall be subject to adjustment as provided for in this Appendix E.

The *firm capacity prices* in Table E-2 are applicable for deliveries of *firm capacity* beginning after December 30, 1982.

E-2 MINIMUM PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments, the *firm capacity* shall be delivered for all of the on-peak hours[1] in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for *forced outages* in any month. Compliance with this provision shall be based on the *Facility's* total on-peak deliveries for each of the peak months and shall exclude any energy associated with generation levels greater than the *firm capacity*.

(b) If Seller is prevented from meeting the minimum performance requirements because of a forced outage on the PGandE system, a PGandE curtailment of Seller's deliveries, or a condition set forth in Section A-7, Appendix A, PGandE shall continue capacity payments. *Firm capacity* payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevented from meeting the minimum performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereaf-

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[1] On-peak, partial-peak, and off-peak hours are defined in Table B-4, Appendix B.

ter, Seller shall be deemed to have failed to have met the minimum performance requirements. *Firm capacity* payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the minimum performance requirements because of extreme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish *firm capacity* pursuant to Section E-8. Seller shall warrant to PGandE that the *Facililty* is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its *firm capacity* obligations.

(e) If Seller is prevented from meeting the minimum preformance requirements for reasons other than those described above in Sections E-2(b), (c), or (d):

(1) Seller shall receive the reduced *firm capacity* payments as provided in Section E-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.

(2) If, at the end of the probationary period Seller has not demonstrated that the *Facility* can meet the minimum performance requirements, PGandE may derate the *firm capacity* pursuant to Section E-4(b).

E-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six

months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 9, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

If Seller has selected Curtailment Option B, off-peak hours of maintenance performed pursuant to Section (d) of Curtailment Option B, Appendix C shall not be deducted from Seller's scheduled maintenance allowances set forth above.

E-4 Adjustments to Firm Capacity

(a) Seller may increase the *firm capacity* with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.

(b) Seller may reduce the *firm capacity* at any time prior to the *firm capacity availability date* by giving written notice thereof to PGandE. PGandE may derate the *firm capacity* as a result of appropriate tests, studies, or prior performance.

E-5 Firm Capacity Payments

The method for calculation of *firm capacity* payments is shown below. As used below in this section, month refers to a calendar month.

The monthly payment for *firm capacity* will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table E-1 based on the *Facility's* interconnection voltage, and the appropriate performance bonus factor, if any, from Table E-3, plus any allowable payment for outages due to scheduled maintenance. The *firm capacity price* shall be applied to meter readings

taken during the separate times and periods as illustrated in Table B-4, Appendix B.

The PPF is determined by multiplying the *firm capacity price* by the following Allocation Factors:[1]

	Allocation Factor	×	Firm Capacity Price	=	PPF ($/kW-month)
Seasonal Period A.....	.16479		_____		_____
Seasonal Period B.....	.02515		_____		_____

The MDC is determined in the following manner:

(1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B\text{-}S) \times (0.8^*)} (\leq 1.0)$$

*0.8 reflects a 20% allowance for *forced outage.*

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the *firm capacity.*

C = *Firm capacity* in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month *Facility* is out of service on scheduled maintenance.

(2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

[1] All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the *CPUC.* Seasonal Periods A and B are defined in Table B-4, Appendix B.

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month *Facility* is out of service on scheduled maintenance.

D = The number of hours in the month.

(3) Determine the MDC by multiplying the MCF by C:

$$MDC \quad (\text{kilowatts}) = MCF \times C$$

The monthly payment for *firm capacity* is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table E-1, and by the appropriate performance bonus factor, if any, from Table E-3.

$$\text{monthly payment for } \textit{firm capacity} = PPF \times MDC \times \text{capacity loss adjustment factor} \times \text{performance bonus factor}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly *firm capacity* payment[1] for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. *Firm capacity* payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section E-3 are met.

During a probationary period Seller's monthly payment for *firm capacity* shall be determined by substituting for the *firm capacity*, the capacity at which Seller would have met the minimum performance requirements. In the event that during the probationary period Seller does not meet the minimum performance requirements at whatever *firm capacity* was established for the previous month, Seller's monthly payment for *firm capacity* shall be determined by substituting the *firm capacity* at which Seller

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[1] Total monthly payment divided by the total number of hours in the monthly billing period.

would have met the minimum performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE E-1

If the *Facility* is non-remote[2] the *firm capacity* loss adjustment factors are as follows:

Interconnection Voltage	Capacity Loss Adjustment Factor
Transmission	.989
Distribution	.991

If the *Facility* is remote the *firm capacity* loss adjustment factor is _____[3]

[2] As defined by the *CPUC*.

[3] Determined individually.

TABLE E-2

Firm Capacity Price Schedule
(Levelized $/kW-year)

Firm Capacity Availability Date	Number of Years of *Firm Capacity Delivery*																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
(Year)																		
1982 ...	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983 ...	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984 ...	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985 ...	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986 ...	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987 ...	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

TABLE E-3

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for *firm capacity* delivered by the *Facility* after it has demonstrated a *firm capacity* factor in excess of 85%.

DEMONSTRATED FIRM CAPACITY FACTOR (%)	PERFORMANCE BONUS FACTOR
85	1.000
90	1.059
95	1.118
100	1.176

After the *Facility* has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

(i) the *firm capacity* factor for each such month shall be calculated in the following manner:

$$\text{FIRM CAPACITY FACTOR (\%)} = \frac{A}{B \times C} \times 100$$

Where:

A = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the *firm capacity*.

B = Total on-peak hours during the month.

C = *Firm capacity* in kilowatts.

(ii) the arithmetic average of the above *firm capacity* factors shall be determined for that span,

(iii) the average of the above arithmetic average *firm capacity* factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Firm Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Firm Capacity Factor not shown in Table E-3 use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Firm Capacity Factor (\%)}}{85\%}$$

SECTIONS E-6 THROUGH E-10 SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

E-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section E-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

E-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section E-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of

each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to —

(1) Release requirements for support of fish life and any other operating constraints imposed on the project;

(2) Operating characteristics of the proposed equipment of the *Facility* such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;

(3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc., and

(4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the *Facility* has water storage characteristics. For the study to show monthly capacity ratings, the *Facility* shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

E-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section E-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The *firm capacity* shown in Article 5 shall not exceed the lowest average

dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July, and August.

E-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

(1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table E-4;

(2) A topographic project map which shows the location of all aspects of the *Facility* and locations of stream gauging stations used to determine natural flow data;

(3) A discussion of all major factors relevant to project operation;

(4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section E-6 and are consistent with generally accepted engineering practices; and

(5) Upon specific written request by PGandE, Seller's theoretical operation study.

E-10 ILLUSTRATIVE EXAMPLE

(1) Determine natural flows—These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".

(2) Perform theoretical operation study—Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This

study is performed based on the *Facility's* design, operating capabilities, constraints, etc., and should take into account all factors relevant to project operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.

(3) Determine average dry year capacity ratings—After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The *firm capacity* is then set by the Seller based on the monthly average dry year capacity ratings and the minimum performance requirements of this appendix. An example project is shown in the attached completed Table E-4.

EXAMPLE

TABLE E-4

Summary of Theoretical Operation Study

Project: New Creek 1

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis

Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics: [1]

	Flow (cfs)	Head (feet)		Output (kW)	Efficiency (%)	
		Gross	Net		Turbine	Generator
Normal Operation ...	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation—Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum *firm capacity*: 410 kW

[1] If *Facility* has a variable head, operating curves should be provided.

E-11 MINIMUM DAMAGES

(a) In the event the *firm capacity* is derated or Seller terminates this Agreement, the quantity by which the *firm capacity* is derated or the *firm capacity* shall be used to calculate the payments due PGandE in accordance with Section (d).

(b) Seller shall be invoiced by PGandE for all amounts due under this section. Payment shall be due within 30 days of the date of the invoice.

(c) If Seller does not make payments pursuant to Section (b), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.

(d) Seller shall pay to PGandE:

(i) an amount equal to the difference between (a) the *firm capacity* payments already paid by PGandE, based on the original *term of agreement* and (b) the total *firm capacity* payments which PGandE would have paid based on the period of Seller's actual performance using the *adjusted firm capacity price.* Additionally, Seller shall pay interest, compounded monthly from the date the excess capacity payment was made until the date Seller repays PGandE, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate; plus

(ii) a sum equal to the amount by which the *firm capacity* is being terminated or derated times the difference between the *current firm capacity price* on the date of termination or deration for a term equal to the balance of the *term of agreement* and the *firm capacity price*, multiplied by the appropriate factor shown in Table E-5 below. In the event that the *current firm capacity price* is less than the *firm capacity price*, no payment under this subsection (ii) shall be due either party.

TABLE E-5

Amount of *Firm Capacity* Terminated or Derated	Factor
1,000 kW or under	0.25
over 1,000 kW through 10,000 kW	0.75
over 10,000 through 25,000 kW	1.00
over 25,000 kW through 50,000 kW	3.00
over 50,000 kW through 100,000 kW	4.00
over 100,000 kW	5.00

APPENDIX L

Decision 87-01-049 January 28, 1987

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, August 10, 1983, October 27, 1983, January 4, 1984, May 4, 1984, June 20, 1984, and August 20, 1986)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1982, August 2, 1983, September 6, 1984, and August 20, 1986)

Application 82-03-26 (Filed March 8, 1982)

Application 82-03-37 (Filed March 8, 1982)

Application 82-03-62 (Filed March 16, 1982)

Application 82-03-67 (Filed March 18, 1982)

Application 82-03-78 (Filed March 22, 1982)

Application 82-04-21 (Filed April 8, 1982)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.

And Related Matters.

OPINION

In its petition for modification of Decision (D.)83-09-054 filed October 29, 1986, Independent Energy Producers Association (IEP) requests that the Commission permit "pioneer" qualifying facility (QF) projects the opportunity to switch to interim Stan-

dard Offer 4. IEP defines "pioneer" projects as QFs now generating under contracts signed prior to September 9, 1983.[1]

IEP's petition emphasizes that the Commission sought to elicit early QF development by providing QFs the option to switch to the final standard offers when they were completed. D.93054[sic], for example, explicitly ordered that language be inserted into early QF contracts permitting conversion of those contracts to the final standard offers. Even after the adoption of the short-run standard offers, many QF contracts included negotiated clauses that guaranteed the QF the right to switch to the final long-run standard offer. Moreover, IEP asserts, still other QFs signed firm contracts only because they believed they would be able to receive the final long-run offer prices once that offer was adopted by the Commission.

IEP notes that the development of a final long-run offer has taken much longer than either the QFs or the Commission anticipated. In fact, delays in adopting a final long-run offer and the desire to stimulate more rapid QF development were primary considerations in the Commission's decision to approve a negotiated interim Standard Offer 4 contract. Because the Commission still hoped to adopt a final long-run offer based on a record developed through evidentiary hearings, the Commission declined to allow QFs already under contract the option to switch to interim Standard Offer 4 (D.83-09-054).

IEP argues that the longer-than-anticipated lapse between the adoption of interim Standard Offer 4 and the adoption of a final long-run offer should lead the Commission to reconsider its ban on contract switching. In IEP's view, the pioneers have been unfairly disadvantaged by the substantial amount of capacity

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[1] Although IEP defines pioneers as those QFs that signed contracts prior to September 9, 1983, it is clear from IEP's petition that it intends to include only those QFs that are now generating under contracts signed prior to the adoption of interim Standard Offer 4. Interim Standard Offer 4 was actually adopted by this Commission on September 7, 1983. All subsequent references to pioneer QFs in this decision shall be construed to mean those QFs now generating under contracts signed prior to September 7, 1983.

coming on line under interim Standard Offer 4. This later QF capacity has the effect of depressing energy prices paid to pioneer QFs at a time when the precipitous drop in oil and gas prices already has caused their energy payments to plummet. According to IEP, many pioneer QFs now receive payments insufficient to meet their debt service obligations. This dramatic decrease in energy payments, IEP believes, could not have been foreseen by a prudent manager at the time these early contracts were signed.

The result of this drop in energy payments may well be to force many pioneer QFs to cease generation or to go out of business entirely. IEP believes that such an outcome is not in the best interest of California's ratepayers or the California economy as a whole. Therefore, IEP requests that the Commission grant the pioneers the option to switch to interim Standard Offer 4 or some variation thereof.

Responses to IEP's Petition

PGandE. PGandE opposes IEP's petition on the grounds that pioneers have no equitable or legal entitlement to switch to interim Standard Offer 4. PGandE emphasizes the importance of balancing the needs of pioneer QFs against the cost to PGandE ratepayers of wholesale extension of interim Standard Offer 4. Although PGandE acknowledges that certain pioneer QFs are experiencing economic hardship, it notes that some pioneers are already operating at a profit. To extend interim Standard Offer 4 terms to these QFs would, in PGandE's view, give them an unwarranted windfall at the ratepayers' expense.

PGandE has already begun negotiating with individual pioneer QFs to restructure their contracts in a way that enables the pioneers to remain in business while providing ratepayer benefits equal or greater to those in the existing contracts. PGandE recommends that the Commission allow pioneer sellers the opportunity to renegotiate their existing contracts before considering across-the-board remedies. Furthermore, PGandE believes that the Commission lacks legal authority to extend interim Standard Offer 4 to pioneer QFs.

PGandE cites seven distinctions among pioneer QFs as evidence in favor of a case-by-case approach. According to PGandE, pioneers differ widely in (1) their financial situations, (2) the nature of their economic problems (unforeseeable vs. self-induced), (3) the use to which they intend to put the additional funds if received, (4) whether a transfer of ownership has occurred since D. 83-09-054, (5) whether the facility burns oil or gas, (6) whether the pioneer seller also holds "gold rush" interim Standard Offer 4 contracts, and (7) whether the seller holds a nonstandard agreement in which PGandE or its ratepayers assumed financial risk or made other arrangements for project financing. Each of these distinctions, in PGandE's view, affects the merit of a pioneer QF's claim for equitable relief from the prohibition on contract switching.

PGandE observes that some pioneer QFs could have switched to interim Standard Offer 4 prior to that offer's suspension. Allowing these QFs an opportunity to reconsider their decision not to switch in light of a hindsight review of the costs and benefits of doing so is unfair, argues PGandE.

Edison. Edison also opposes IEP's petition. Central to its argument are two premises. First, at the time they entered into their contracts, pioneer QFs knowlingly accepted certain risks with respect to future Commission-developed contracts and prices. Second, permitting pioneer QFs to switch to interim Standard Offer 4 would be prohibitively costly to Edison's ratepayers. As further support of its position, Edison notes the potential for any relief granted to be contrary to the final report and recommendation of the Commission to the legislature under SB 2674, which requires the Commission to submit no later than May 1, 1987, a report on the problems of pioneer QFs and potential remedies. Edison also cites several Commission orders that it believes provide a clear precedent for maintaining the ban on contract switching.

In the event the Commission decides to grant relief to pioneer QFs, Edison urges that such relief be provided on a case-by-case basis through either negotiated settlement or individual QF petitions for modification of D.83-09-054. In addition, Edison would

limit any relief to those QFs with clauses in their contracts allowing them to switch to the final long-run offer.

SDG&E. SDG&E echoes the position of the other two utilities that permitting pioneer QFs to switch to interim Standard Offer 4 would simply be too costly to its ratepayers. Furthermore, SDG&E believes that the financial risk undertaken by pioneer QFs was clearly understood at that time and was not predicated on an assumption of the right to switch to interim Standard Offer 4. Moreover, SDG&E is not convinced of the claims by IEP that pioneer QFs as a class have been severely impacted by the downturn in avoided cost. Finally, SDG&E cites numerous legal and contractural barriers to allowing pioneer QFs the opportunity to switch to interim Standard Offer 4. If the Comission wishes for equitable reasons to extend the benefits of interim Standard Offer 4 prices to pioneer QFs, SDG&E recommends that the prices received by QFs coming on line after the pioneers be reduced by a comparable amount to ensure that ratepayers receive the benefits to which they are entitled.

Discussion

The fundamental question before the Commission is one of timing. Pioneer QFs (i.e., those that signed contracts prior to the adoption of interim Standard Offer 4) provided the ratepayers with a valuable service at a time when the ability of the utilities' own central-station generation facilities to serve the growing demand for electricity was in question. These pioneers faced substantial risks by coming on line prior to the availability of a long-run standard offer that would fully recognize their contribution to the reliability of the utilities' systems. Moreover, while the electrical capacity currently available to California is ample, there is every reason to expect that the output from pioneer QFs will again be greatly needed well within the economic life of their power plants. The question, then, is whether pioneer QFs are to fall or survive solely on the basis of their relatively low short-term benefits to the system or whether we should recognize now, through increased price stability, their undoubtedly greater value considering economic lives of 20 to 30 years or more.

PGandE argues that the decision to take such a risk (i.e., that short-term prices would drop drastically) is a normal element of doing business and that the entire premise of PURPA is to rely on market forces rather than cost-of-service ratemaking. We agree with this general characterization of the QF program; however, the unique circumstances surrounding the pioneer QF problem are sufficient to warrant special consideration.

Given the conditions under which this Commission initiated the QF program, we find IEP's assertions regarding the expectations of pioneer QFs plausible. Many pioneers made the decision to enter into early contracts only because they believed this Commission implicitly or explicitly assured them of the right to convert to a final long-run offer once such an offer was adopted. Such expectations were a reasonable reading of the Commission's orders and statements regarding the QF program; it has always been the Commission's intention that those who answered the call when QF energy was most urgently needed would be appropriately compensated for the risks they undertook.

Unfortunately, the regulatory process has not moved as rapidly as we had hoped. Developing a market-based approach to resource planning has been a rewarding but time-consuming endeavor. Today, more than three years after the adoption of interim Standard Offer 4, we are still at least several months away from adopting a final long-run standard offer. We do not believe that this Commission or the QFs signing early contracts ever anticipated delays of this magnitude. Certainly, we did not expect such delays when we precluded pioneer QFs from switching to interim Standard Offer 4 in D.83-09-054.

Another unintended result of the lengthy process of developing a final long-run offer is that the magnitude of QF development under the interim offer has substantially reduced the need for, and therefore the value of, QF capacity under a final long-run offer. It is unlikely that any offer will be available in the near future that provides a fair measure of the value of the capacity that pioneer QFs brought to the utilities' systems.

These delays and the attendant reduction in the value of QF capacity to the utilities' systems have significantly reduced the

value and meaning of the option to switch to a final long-run offer. Therefore, we concur with IEP that it is appropriate at this time to reconsider our ban in D.83-09-054 on contract switching.

These delays and the attendant reduction in the value of QF capacity to the utilities' systems have significantly reduced the value and meaning of the option to switch to a final long-run offer. Therefore, we concur with IEP that it is appropriate at this time to reconsider our ban in D.83-09-054 on contract switching.

We cannot, however, ignore the real cost to ratepayers of permitting the pioneers to be paid interim Standard Offer 4 prices. Our decision to suspend the availability of interim Standard Offer 4 (D.85-04-075) reflected our awareness that, considering the number of QFs signing up, the prices in that offer overvalued the energy and capacity value of QF power. Since our supension order, additional QF development under Standard Offer 2 and the drop in oil and gas prices has further reduced the value to ratepayers of additional energy and capacity. The potential for significant overpayments is, in our view, sufficient reason to deny IEP's request that pioneers be allowed to switch to interim Standard Offer 4 contracts.

Balancing the claims of pioneer QFs against the potential for overpayments is difficult. None of the parties in this matter have offered us a viable middle ground. At this time, the suggestion of PGandE and Edison to attempt negotiated settlements with pioneer QFs appears to have the greatest potential for preserving the benefit of the pioneers' contribution to the reliability of the utility systems without unduly burdening ratepayers with increased payment exposure. We note that PGandE has already entered into negotiations with several pioneer QFs and wish to give those negotiations an opportunity to bear fruit before we consider any other solution to the problems of pioneer QFs.

Our decision to postpone further Commission action to allow time for negotiation does not indicate a lack of concern for the problems of pioneer QFs. Indeed, the potential of negotiated settlements to tailor relief more appropriately to the needs of specific projects is one of the reasons we prefer seeking negotiated agreements. We are also concerned, however, that relief be

provided in a timely manner. As the utilities noted in their responses to IEP's petition, this Commission must report to the legislature by May 1, 1987, regarding the pioneer QF problem and possible solutions. To ensure that any negotiations mesh well with [sic] this timetable, we will require the utilities to report to us by March 1, 1987, on the extent of the pioneer QF problem in their service territories and the progress they have achieved in negotiating settlements with pioneer QFs.[2] If those reports suggest that negotiations are unlikely to achieve a balanced solution to the pioneer QF problem, we will reconsider the merits of an across-the-board solution.

Findings of Fact

1. Many pioneer QF contracts contain explicit provisions allowing the QF to convert to the final long-run offer once such an offer is adopted by this Commission.

2. The adoption of a final long-run offer has been delayed significantly in comparison with the expectations of the Commission, QFs and the utilities at the time interim Standard Offer 4 was adopted.

3. The substantial amount of QF capacity signed under interim Standard Offer 4 contracts has significantly reduced the value of additional QF capacity and the likelihood that the Commission will make a final long-run offer available in the near future.

4. In D.85-04-075, the Commission suspended interim Standard Offer 4 because, given then-current expectations, the capacity payments and fixed, forecasted energy payments in that offer overstated the value to ratepayers of QF power.

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[2] The relief that we seek to provide to pioneer QFs is limited to redressing the unintended effects of our ban on contract switching in D.83-09-054. Therefore, we do not believe that relief should be provided to any QF that had the opportunity to switch to interim Standard Offer 4 during the period when that offer was available. We expect the utilities to negotiate accordingly.

5. Without some form of relief from the current low short-term avoided cost payments, many pioneer QFs may cease generation or go out of business entirely.

6. Negotitated contracts offer an oportunity to tailor relief appropriately to the individual needs of specific pioneer QF projects.

Conclusions of Law

1. Unanticipated delays in the adoption of a final long-run offer justify reconsideration of the Commission's decision in D.83-09-054 to prohibit pioneer QFs from switching to interim Standard Offer 4.

2. The potential for substantial overpayments under interim Standard Offer 4 pricing terms is sufficient reason to deny IEP's request that pioneers be allowed to switch to interim Standard Offer 4 pricing terms.

3. Pioneer QFs should receive some degree of insulation from the effects of subsequent QF development on their energy prices.

4. Those pioneer QFs that had an opportunity to insulate themselves from the effects of subsequent QF development on their energy prices by switching to interim Standard Offer 4 should not be protected from the consequences of their business judgment by gaining a second opportunity to obtain some degree of pricing certainty. Therefore, QFs that had the opportunity to switch to interim Standard Offer 4 should be precluded from any relief from the terms of their existing contracts.

ORDER

IT IS ORDERED that PGandE, Edison, and SDG&E shall file with the Commission's Docket Office an original and 12 copies, by March 1, 1987, of a report detailing the extent of pioneer QF development in their respective service territories and the progress achieved in negotiating agreements with individual pioneer QFs.

This order is effective today.

Dated January 28, 1987, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
Commissioners

APPENDIX M

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to—

(1) sell electric energy to qualifying congeneration facilities and qualifying small power production facilities[1] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

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[1] So in original. Probably should be followed by a comma.

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public inteest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power

production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C. 791a et seq.], from the Public Utility Holding Company Act [15 U.S.C. 79, et seq.], from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragrpah (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act [15 U.S.C. 79 et seq.] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f) of this section,

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C. 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 U.S.C 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C. 791a et seq.] any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utitily for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) of this section in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f) of this section. Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) of this section with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C. 824 et. seq.], such rule shall be

treated as a rule under the Federal Power Act [16 U.S.C. 791a et seq.]. Nothing in subsection (g) of this section shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) of this section against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) of this section shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C. 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) of this section[2] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) of this section as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

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[2] So in original. Probably should be followed by a comma.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C. 796(17), (18)].

(Pub. L. (95-617, title II, § 210, Nov. 9, 1978, 92 Stat. 3144; Pub. L. 96-294, title VI, § 643(b), June 30, 1980, 94 Stat. 770.)

APPENDIX N

Finance Insurance and Commerce Committee
Alister McAlister, Chairman

Assembly Bills 1402 and 1403—Hayes—As introduced

Fiscal Committee: Yes

Hearing Date: January 16, 1980

Background

At the present time, a small number of private companies are able to generate electricity as a by-product of their manufacturing processes through what is known as cogeneration. Cogeneration is the generation of electricity from the exhaust steam, waste steam or heat created by an industrial, commercial or manufacturing plant in the manufacturing process.

Companies which are able to generate electricity by using cogeneration technology consume that electricity for their own operations. However, when they do not need the electricity they have generated, they sell it to electric utilities which serve the public, such as PG&E.

Analysis

AB 1402 and AB 1403 encourage the development of electricity through cogeneration technology in two different but related ways.

AB 1402. AB 1402 would require the State Energy Commission and the Public Utilities Commission jointly to conduct a review of standby rates which are charged by electric utilities to companies which employ cogeneration technology. (A standby rate is what a utility charges a company which employs cogeneration technology for the utility to provide standby generation, transmission and distribution facilities.) After conducting a review, the PUC would establish standby rates which would encourage the utilization of electricity produced through cogeneration technology and a reasonable return to electric utilities so that they would recover their costs of providing standby services.

AB 1402 also makes technical changes in the Public Utilities Code by renumbering sections dealing with automatic dialing-announcing devices.

AB 1403. AB 1403 requires the State Energy Commission and the Public Utilities Commission jointly to conduct a review of the compensation offered by utilities to companies which utilize cogeneration technology to produce electricity which can be sold to utilities. Following a review, the PUC would be required to approve and establish rates electric utilities must pay to companies from which they purchase electricity created by cogeneration technology. The PUC could act on its own motion, upon recommendation of the State Energy Commission or upon application from a private company.

AB 1403 also makes technical changes to sections of the Public Utilities Code by renumbering various sections dealing with automatic dialing-announcing devices.

COMMENTS

AB 1402 and AB 1403 were introduced by the author to encourage the development of electricity through cogeneration technology by requiring the PUC to establish standby rates and rates for purchasing electricity from companies which use cogeneration technology which will encourage electrical utilities to enter into contracts with companies utilizing cogeneration.

The PUC has been working on cogeneration since it initiated OII No. 26 last year to review Pacific Gas and Electric's resource plans for purchasing electricity from cogeneration sources. In two decisions issued on December 19, 1979 (OII No. 26 and Rate Case Decision 91107), the commission found that PG&E should have entered into contracts to purchase 3,000 megawatts of electricity from cogeneration sources. PG&E was ordered to enter into contracts to purchase 600 megawatts in 1980, 400 megawatts during 1981 and another 1,000 megawatts by 1985. PG&E was penalized $7 million on its rate of return for being deficient in entering contracts with cogenerators. However, the penalty will be removed when it satisfies the above contract schedule.

The December 19th decisions accomplish the intent of AB 1402 and AB 1403 because the decisions establish a bases for standby rates and compensation which must be paid for purchasing electricity from cogenerators. The decisions encourage cogeneration technology. The standby rates charged by utilities to companies utilizing cogeneration technology must be set at a utility's "average cost." That is, at a cost which averages the utility's high and low costs of producing electricity. "Average cost" pricing tends to be lower than other pricing methods.

The commission's decisions require that rates paid by utilities for electricity produced from a company which utilizes cogeneration technology must be at a utility's "avoided cost." "Avoided costs" reflect the costs of building new power plants to generate electricity that can be purchased elsewhere. Because construction costs are high and tend to reflect inflationary pressures, avoided costs are usually high. The result of the PUC's decisions is that PG&E will charge a lower rate for providing standby services to companies which utilize cogeneration technology than the companies will charge PG&E for electricity it purchases from them. Companies will be encouraged to enter into contracts with PG&E to purchase their electricity because of the favorable rates they can charge. PG&E will have to enter into contracts because of the decision of the PUC that it purchase 2,000 megawatts of electricity from cogeneration sources by 1985.

According to the PUC, it has been working with the State Energy Commission on an informal basis to analyze standby rates. This has resulted in a 46 percent reduction in standby rates charged by PG&E, Southern California Edison and SDG&E.

Technical Amendments

AB 1402 and AB 1403 would both add Section 2821 to the Public Utilities Code in different forms. Section 2821 in AB 1402 requires the commission to establish standby rates charged by electric utilities. Section 2821 in AB 1403 requires the commission to approve and establish rates paid by utilities for electricity purchased from companies which employ cogeneration technology. It is recommended that these two sections be combined into

one section in either bill in order to accomplish the author's purpose and to eliminate any chaptering problems.

The provisions of AB 1402 and AB 1403 apply only to private utilities regulated by the PUC. In order to further encourage cogeneration technology, the provisions of these bills should also apply to municipal utilities that produce electricity for the public.

The following have expressed interest in this measure:

Public Utilities Commission (neutral)

Supreme Court, U.S.
FILED
AUG 26 1987
JOSEPH F. SPANIOL, JR.
CLERK

No. 87-178

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
Petitioner,

v.

PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA, et al.,
Respondents.

BRIEF OF RESPONDENT BASIC AMERICAN FOODS, INC. IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

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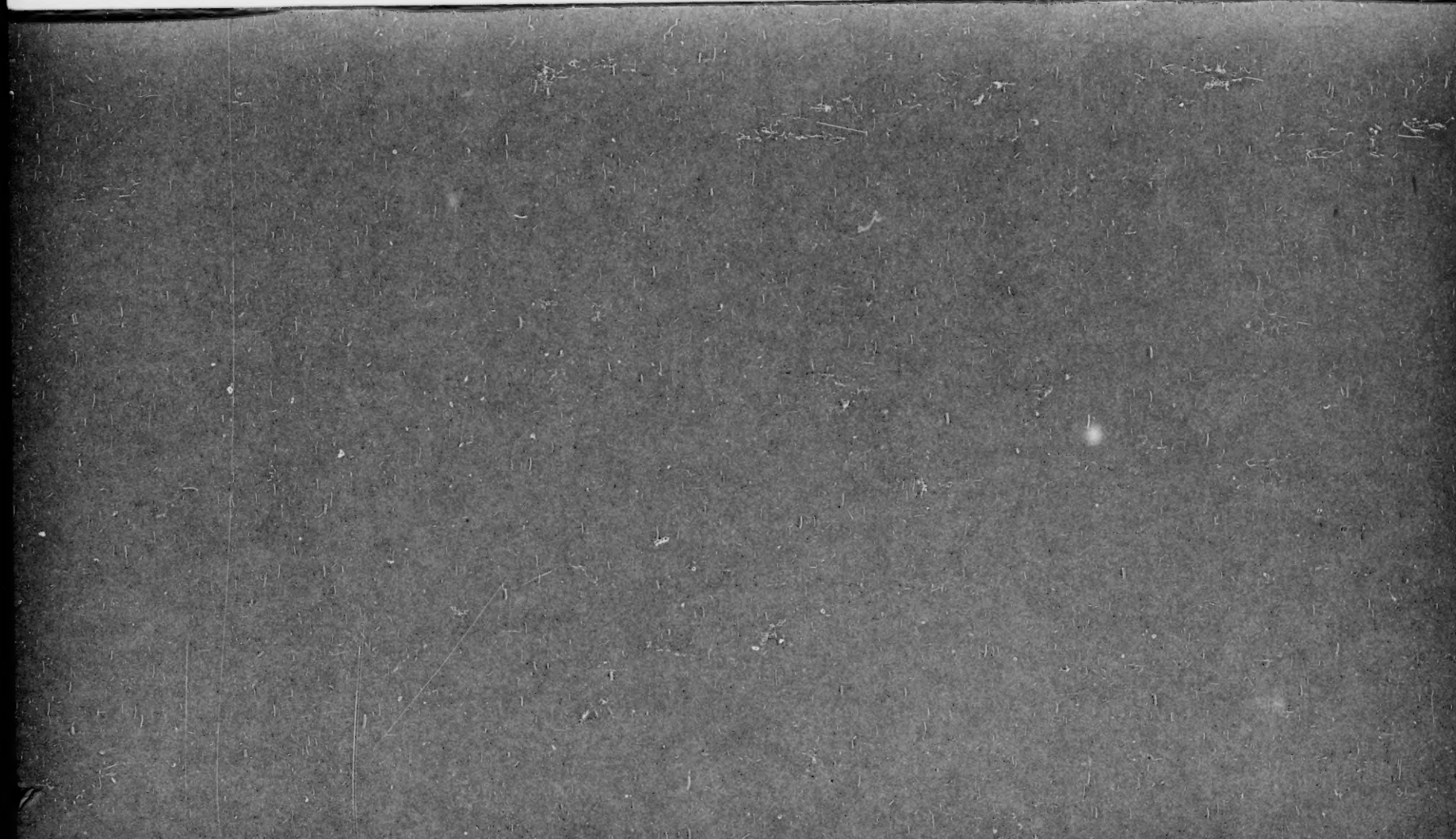

QUESTION PRESENTED

Whether the California Public Utilities Commission (CPUC) acted consistently with the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) in construing the price terms of a long-term standardized power purchase agreement, previously adopted by the CPUC in implementing its mandate under PURPA, to require payment of prices based on forecasts of long-run avoided costs as of the date the agreement was negotiated even though such long-run prices may now exceed current estimates of avoided costs.

RULE 28.1 STATEMENT

Basic American Foods, Inc. is a privately held corporation having no parent and no non-wholly owned subsidiaries or affiliates.

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PUBLIC UTILITIES COMMISSION OF
THE STATE OF CALIFORNIA, et al.,
Respondents.

BRIEF OF RESPONDENT BASIC AMERICAN FOODS, INC. IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

Respondent Basic American Foods, Inc. (Basic) submits this brief in opposition to the Petition for Writ of Certiorari filed by Petitioner Pacific Gas and Electric Company (PGandE).

STATEMENT OF THE CASE

This case involves the interpretation of agreements entered into pursuant to regulations issued by the California Public Utilities Commission (CPUC). On September 3, 1980, the CPUC instituted regulatory proceedings on the subject of the purchase by electric utilities of power generated by independent entities. These proceedings were designed to carry out the statutory policies of the Public Utility Regulatory Policies Act of 1978 (PURPA) and its California counterpart codified as Chapter 7 of the California Public Utilities Code §§ 2801-2824. These policies were to promote competition, conservation, and decentralization in electric power generation through the encouragement of

cogeneration projects and small alternative fuel electric generation facilities.

The CPUC chose as the vehicle for carrying out policy in this area the development of Standard Offer contracts pursuant to which California electric utilities would be required to purchase electricity from qualifying facilities (often referred to as QFs). In the first two decisions issued under its regulatory proceedings, the CPUC established Standard Offers 1 through 3 which governed the purchase of electric power at prices based on short-run avoided costs. *See*, D.82-01-103, 8 C.P.U.C. 2d 20 (1982); D.82-12-120, 10 C.P.U.C. 2d 553 (1982). The CPUC also recognized that short-run avoided costs were prone to sudden and dramatic changes in response to volatile market conditions. Because of such contract price uncertainty, QFs experienced great difficulty arranging financing for their projects. In order fully to carry out the policy of the federal and California statutes by providing QFs with a level of price certainty that would facilitate project financing, the CPUC determined that it must develop and implement promptly a Standard Offer with long-run as opposed to short-run pricing provisions. D.83-09-054 (1983), (Petitioner's Appendix at A-4-5).[1]

In September 1983, following lengthy negotiations involving Petitioner PGandE, the other major California electric utilities, representatives of consumer and QF interests, and the CPUC staff, the CPUC adopted interim Standard Offer 4 (interim SO4). Interim SO4, as agreed to by PGandE and the other participants in the negotiations, provided for the purchase of electric power for terms of from 15 to 30 years. Like the earlier short-run Standard Offers, the pricing provisions involved both "capacity" and "energy" elements.[2]

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[1]Subsequent citations to Petitioner's Appendix will be indicated by the letter A followed by the appropriate page in the Appendix.

[2] The capacity pricing elements specified in interim SO4 (which were essentially incorporated from the earlier Standard Offer 2) were calculated to equal "avoided shortage costs, related to the peaking firm capacity the utility can avoid (based on the rental value of a combustion turbine)." D.83-09-054 (1983), (A-19). The energy elements were

In general, firm capacity prices would be fixed and level over the entire term of the contract while energy prices could be fixed only for the first 10 years of operations. The combination of fixed energy and firm capacity payments produced the intended result that a QF could project long-term revenues at the time it signed a contract pursuant to interim SO4 and base its plans and financing on those revenue projections. As the CPUC noted with regard to energy payments:

> The QF project must be on line within 5 years from the date the agreement is executed. However, the QF agrees to the payment stream, based on the forecast, when the contract is signed. This means utilities must have a 15-year forecast when the contract is signed to allow for a maximum 5-year hiatus before operation and payments start after contract execution.

D.83-09-054 (1983), (A-19).

Unfortunately, there were inadvertent omissions in certain of the tables in the agreements executed by QFs pursuant to interim SO4. For example, the CPUC's September 1983 decision approving interim SO4 specified that, subject to further order, interim SO4 would be in effect for at least six months but no more than two years. D.83-09-054 (1983), (A-44). The projected energy prices in Table B-1 of the interim SO4 agreement prepared by PGandE, however, covered only the years 1983 through 1997 so that the 15-year forecast referred to by the CPUC was short from its inception by at least one and possibly three years.[3] Similarly,

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based on "a forecast of utility's marginal energy cost." D.83-09-054 (1983), (A-19, n.3).

[3] As prepared by PGandE, Table B-1 provided energy prices from 1983 to 1997. If interim SO4 had remained available only for the minimum anticipated six months, a QF executing an agreement in early 1984 that required the full five years to commence operations would need fixed energy price estimates until early 1999. If the agreements were to remain available for the maximum two years contemplated, a QF could execute a contract as late as September 1985 and its contract would require fixed energy price estimates extending until September 2000.

Table E-2 was simply carried over from Standard Offer 2 and provided firm capacity prices only for projects that established their ability to supply firm power between 1982 (one year before interim SO4 was even approved) and 1987, instead of between 1983 and 1990—the years when the interim SO4 projects could actually begin firm operations.

In August 1984, at the request of QF interests and with no objection from PGandE, the CPUC acted to extend certain interim SO4 options that otherwise would have expired in September 1984. In April 1985, the CPUC suspended prospectively the availability of interim SO4, and it is now in the process of replacing it with a permanent long-run Standard Offer.

In the meantime, however, the inadvertent omissions in the tables attached to interim SO4 agreements became apparent. Respondent Basic, for example, had signed a contract in November 1984 to supply PGandE with energy and capacity from a 120 megawatt cogeneration project—designed to produce heat that would be used in Basic's food dehydration plant and to generate electricity from the waste heat—to be built in King City, California.[4] Basic's original plan was to commence operations by 1987. Because of delays in obtaining needed siting permits, however, it became apparent by 1986 that Basic would not be able to commence deliveries of power until 1988. QFs which had signed contracts with the other major California electric utilities had asked for and obtained clarifications extending Tables B-1 and E-2. PGandE, however, refused Basic's request for such clarification and took the position that unless Basic's cogeneration facility commenced operation before 1988, the contract would provide no fixed capacity prices and less than the full ten years of forecasted energy prices.[5] In the absence of such specified prices, PGandE

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[4] Basic represents the type of QF that PURPA was designed to encourage since its large thermal heat needs provide a significant opportunity for efficient cogeneration.

[5] Basic's major competitor initiated a program to develop a similar 120 megawatt cogeneration project. Although Basic and its competitor executed similar interim SO4 contracts, PGandE agreed to extend the competitor's Table E-2 to provide firm capacity prices, notwithstanding

would pay Basic only "reasonable" prices based on short-run avoided costs at the time of delivery.[6]

In three orders issued between October and December 1986 (A-126 through A-148), the CPUC considered applications by Basic and similarly situated QFs seeking clarification of their entitlement to fixed price certainty under their interim SO4 contracts and correction of the inadvertent omissions in the appended tables. Rejecting PGandE's arguments as inconsistent with the purpose and language of interim SO4 and with the intent of the parties in negotiating the long-run contracts, the CPUC ordered PGandE to do what was required by the terms of the agreement and what the other California electric utilities had agreed to do voluntarily.

In particular, the CPUC held that the methodology used to generate the firm capacity prices of Table E-2 should be carried forward to calculate prices for projects whose capacity became available in 1988, 1989, and 1990—thereby accomplishing what PGandE itself had previously urged was a "ministerial" task in seeking a similar adjustment to the firm capacity price table in Standard Offer 2, the very same table that was incorporated into interim SO4. (A-134, n. 11). Because there was no similar methodology readily available in the case of energy prices, the CPUC simply ordered PGandE to extend the 1997 price through the year 2000, thereby ensuring the full 10-year fixed payment stream contemplated by interim SO4.[7] The CPUC considered

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that the competitor would not begin deliveries until 1988, but refused Basic's request for similar treatment.

[6] To put PGandE's position in perspective, it should be recognized that PGandE perceives QFs to be competitors. While QFs do not compete with PGandE in retail sales of electricity, QF power plants supplant utility power plants which constitute a significant portion of the utility's rate base upon which a utility's rate of return is applied.

[7] The CPUC also rejected PGandE's argument concerning "as-delivered" capacity and ordered the 1997 price in Table D-2 extended for the years 1998-2000. This part of the CPUC order is not in issue since, as PGandE concedes, the interim SO4 agreement otherwise produces the same result.

and rejected PGandE's contention that it was ordering "new" prices and found that extension of the tables was necessary to construe the agreement logically and conform the interim SO4 agreement to the purposes underlying its adoption and to the parties' intent.[8]

On April 30, 1987, the California Supreme Court denied PGandE's petition for a writ of review of the CPUC orders. Under California law, the court's action constituted a rejection on the merits[9] of PGandE's claims presented to the court that the CPUC's interpretation of the interim SO4 agreements violated earlier regulatory pronouncements, incorrectly applied California law, and thereby established prices higher than those required to satisfy the avoided costs standard mandated by Section 210(b) of PURPA. By its present Petition for Writ of Certiorari, PGandE essentially asks this Court to reverse the California Supreme Court's rulings on these issues.

REASONS FOR DENYING THE WRIT

No substantial federal question is raised in the Petition. The CPUC decisions at issue involve no more than the agency's interpretation of the terms of contracts entered into pursuant to interim SO4. In its simplest terms, the Petition argues that the CPUC, the agency best suited to make the determination at issue, acted inconsistently with PURPA by incorrectly interpreting the agreements under state law. In fact, the underlying issues of state

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[8] In connection with extending Table E-2, the CPUC stated that it was "[C]onstruing the express terms to give them their clear and logical effect." (A-135). In extending Tables B-1 and D-2, the CPUC stated, "The intent of the parties in placing Table B-1 into [interim SO4] was to provide for energy price certainty for up to ten years for each QF signing under that contract . . . The same is true for Table D-2, which represents as-available capacity prices." (A-146).

[9] The California Supreme Court's denial of a petition for a writ of review of an order from the CPUC constitutes a decision on the merits for purposes of *res judicata*. *See*, *Consumers Lobby Against Monopolies v. Public Utilities Commission*, 25 Cal.3d 891, 901, 603 P.2d 41, 160 Cal. Rptr. 124 (1979).

law were decided correctly and would, in any event, not be properly reviewed in this Court. Furthermore, by its very terms, the Standard Offer that led to the agreements at issue was interim in nature, subsequently suspended, and unique to California. No question of national application or importance is presented, nor is the decision below in conflict with the decision of any other court. At most, the decision can be argued to raise by strained implication an issue previously determined by this Court not to present a substantial federal question when it dismissed the appeal in *Consolidated Edison Co. v. Public Service Commission*, 470 U.S. 1075 (1985).

A. Petitioner Has Misstated The Question Presented

PGandE misstates the nature of the proceedings below and incorrectly frames the question presented by repeatedly characterizing the CPUC's actions as establishing "new" prices added to existing interim SO4 agreements. Thus Petitioner concludes that the federal question involved is whether the CPUC's adoption of "new" prices is in conflict with the avoided costs standard of PURPA, in this process comparing the "avoided costs" forecasts negotiated in 1983 and embodied in the interim SO4 agreement with estimates of "avoided costs" presented by PGandE in 1986 when the CPUC construed the interim SO4 agreements. PGandE ignores the CPUC's rejection of PGandE's repeated allegations that "new" prices were being added and its conclusion that the extension of the price tables simply made available to QFs the fixed price certainty that was the "crux" of interim SO4 and upon which the QFs had substantially relied. (A-129).

The question presented, properly framed, is whether the CPUC acted consistently with PURPA and the regulations of the Federal Energy Regulatory Commission (FERC) thereunder when it construed the terms of a long-term standard offer power purchase agreement to require payment of prices based on negotiated forecasts of long-run avoided costs that were determined when the agreement was made available to QFs, even if such prices may for the moment exceed later estimates of avoided costs. So stated, it is apparent from the discussion that follows that the federal question is insubstantial and that the issue was properly decided below.

The FERC regulations give the CPUC wide latitude in implementing PURPA. 18 C.F.R. § 292.401(a) (1987). This latitude includes the authority to adopt standard offer power purchase agreements for specified terms. 18 C.F.R. § 292.304(d)(2) (1987). Furthermore, in determining "avoided costs," the FERC regulations direct the CPUC to consider various factors, one of which is "the terms of any contract or other legally enforceable obligation including the duration of the obligation. . . ." 18 C.F.R. § 292.304(e)(2)(iii) (1987). The CPUC is expressly authorized to implement the FERC regulations by establishing prices based on avoided cost estimates in effect at the time a contract is signed. 18 C.F.R. § 292.304(d)(2) (1987). If contracts of specified terms are used, "the rates for such purchases do not violate [PURPA] if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. § 292.304(b)(5) (1987).

Both state law and the FERC regulations implementing PURPA authorize the CPUC to resolve questions involving the obligations of utilities to purchase QF power. *Compare*, Cal. Pub. Util. Code §§ 701, 702, 1702, 2821 (West 1975 & Supp. 1987) *with* 18 C.F.R. § 292.401(a) (1987). PGandE's contention that, in extending the tables at issue, the CPUC added "new" prices challenges only the CPUC's application of state law in a factual inquiry undertaken to interpret the meaning of the agreements in light of the parties' intent and the purposes and policies embodied in the original CPUC decision approving interim SO4.

The CPUC found that the parties had intended and interim SO4 required that fixed price certainty would be available to all QFs that had executed the agreements and were able to commence operations within the agreement's five year deadline. It was well understood by all parties involved in the proceedings that led to interim SO4, including PGandE, that actual avoided costs at the time of delivery would, over the term of the resulting agreements, depart from the avoided costs that were forecasted in 1983. D.83-09-054 (1983), (A-6).

Moreover, PGandE's unsupported and grossly inaccurate assertion that the three decisions will result in a $1 billion ratepayer subsidy to QFs is misleading and misses the point entirely. The interim SO4 agreements are for 15-30 year terms and there

simply is no way to know whether over the long-term interim SO4 prices will prove to be higher or lower, in the aggregate, than avoided costs at the time the power is delivered.[10] The point is that the interim SO4 prices were based on forecasts of long-run avoided costs at the outset, not short-run costs calculated at various times during the term of the agreements. Whether the original forecast adopted in interim SO4 may now exceed estimates of current avoided costs is irrelevant since such a risk was contemplated and expressly provided for at the outset and such a situation is expressly permitted under the FERC regulations.

B. The Federal Question Raised Below Is Not Only Insubstantial But Also Unique And Unlikely To Recur

Each state regulatory authority is charged under PURPA with the duty of implementing the rules promulgated by the FERC. Section 210(f)(1), 16 U.S.C. § 824a-3(f)(1) (1987). The state regulatory authority is given wide latitude in how it elects to implement the FERC rules. 18 C.F.R. § 292.401(a) (1987). Moreover, the FERC rules do not specify what avoided costs will be but instead instruct the state regulatory authority to determine avoided costs by evaluating "to the extent practical" the factors listed in 18 C.F.R. § 292.304(e) (1987). Thus, the implementation of PURPA contemplates a wide diversity both in the methods chosen by the state regulatory authorities to implement

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[10] In his recent testimony before the FERC submitted March 27, 1987, Commissioner Stanley Hulett, President of the CPUC, emphasized this very point by stating:

> The CPUC believes that any overpayments that may occur in the early years of these [interim SO4] contracts has to be put in a proper context. We agree that, when compared to short-run avoided costs in 1990, QFs under the interim long-run standard offer will be receiving payments in excess of short-run avoided costs. However, the CPUC believes that this is not the correct standard of comparison. These QFs are long-run resources, with contract lengths of up to thirty years. To compare a long-run resource with short-run avoided costs in one year is incorrect and misleading; the proper standard is to view these contracts over their life and, on that basis, these QFs could be some of the best deals utilities have.

PURPA's requirements and in the valuation of avoided costs within each state.

No substantial question of national importance involving the proper implementation of PURPA by state regulatory authorities is raised that merits this Court's review. This is so because the scope of the CPUC's action is narrow, limited to resolving a state law question of contract interpretation. The omission in the tables attached to interim SO4 agreements necessitated an interpretation by the CPUC to clarify whether QFs beginning operations after 1987 but within the agreements' five year deadline were entitled to the same fixed price certainty for energy and capacity prices as QFs that had executed the same agreements but commenced operations before 1988, notwithstanding the failure of the appended price tables to contain the full range of fixed prices necessary to provide all QFs with such uniform treatment.

No recurring issue or broad question of federal policy under PURPA is involved. The likelihood that either the CPUC or any other state regulatory authority will be faced in the future with a need to interpret a similar agreement and resolve conflicting interpretations over the level of price certainty available under that agreement is extremely remote and inconsequential to the implementation of a national energy policy under PURPA. The issue addressed by the CPUC is neither one of national application nor importance. Furthermore, the interpretation reached by the CPUC in this case is entirely consistent with PURPA's policy of encouraging private energy development.

C. The Decision Below Affirms The CPUC's Resolution Of A Fact Specific Inquiry Undertaken By The Agency Best Suited To Make That Determination

Any validity to the Question Presented in the Petition must hinge on PGandE's contention that the interim SO4 power purchase agreement, as originally approved by the CPUC, does not permit the construction given to it by the CPUC. Thus, Petitioner invites this Court to substitute its own judgment for that of the CPUC and reject the CPUC's construction of the agreement as affirmed by the California Supreme Court's denial of review. Certiorari should not be granted simply to review

evidence and discuss specific facts. *United States v. Johnston*, 268 U.S. 220, 227 (1925).

No substantial federal question is presented when the question involves solely the application of state law by a state regulatory authority charged with the duty of implementing a federal statute in a manner that it deems appropriate in light of its experience and expertise. Such expertise has been vested in the CPUC. The application of such expertise by the state regulatory agency that was responsible for originally implementing the contracts involved and is thereby best suited to resolve the matters at issue simply does not warrant the review of this Court.

D. No Conflict Exists In The Decisions Of State Courts That Justify This Court's Review Of The Decisions Below

Petitioner incorrectly asserts that a conflict in the application of federal law exists between this case and two inconsistent state court decisions, *Consolidated Edison Co. v. Public Service Commission*, 63 N.Y. 2d 424, 472 N.E. 2d 981, 483 N.Y.S. 2d 153 (1984), *appeal dismissed*, 470 U.S. 1075 (1985) and *Kansas City Power and Light Co. v. State Corp. Com'n*, 234 Kan. 1052, 676 P.2d 764 (1984). Petition at 14. No such conflict exists because both of these cited cases are inapposite to the legal issue presented herein.

Both *Kansas City Power* and *Consolidated Edison* involve the adoption of prices under state law independent from PURPA that were intended to depart from and at times exceed the avoided cost standard of PURPA. In this case, the CPUC never intended to depart from PURPA and adopt under state law prices that exceed avoided costs. The prices originally adopted in the long-term interim SO4 agreement are negotiated estimates of long-run avoided costs that are entirely consistent with PURPA and the implementing FERC regulations. That the long-run avoided costs originally adopted in interim SO4 may exceed PGandE's estimate of avoided costs determined at some later time is expressly permitted under, and thus does not violate the avoided costs standard required by, PURPA and the implementing FERC

regulations. Thus, the purported conflict raised by PGandE is nonexistent.[11]

In any event, in dismissing the appeal in *Consolidated Edison*, this Court concluded that no substantial federal question was presented by a state court decision expressly holding that PURPA does not preempt the field, but allows states to promote greater QF development by adopting prices that exceed the avoided costs standard established under federal law. *A fortiori*, no substantial federal question is presented when, even to reach this issue, this Court would have to examine and reverse the CPUC's decisions as to the intent of the parties to the interim S04 negotiations and the proper interpretation of interim S04 agreements under state law.

CONCLUSION

For all the reasons stated above, the Petition for Writ of Certiorari should be denied.

August 25, 1987

Respectively submitted,

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[11] Given that the CPUC did not purport to adopt prices in excess of the avoided costs standard of PURPA, there is no need to consider whether California Public Utilities Code § 2821 would independently authorize the CPUC to adopt "equitable charges" in excess of such costs. Had the CPUC expressly relied on state law to adopt higher than avoided cost prices, then the conflict with *Kansas City Power* that PGandE strains to construct might exist.

Supreme Court, U.S.
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No. 87-178

IN THE

Supreme Court of the United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation,
Petitioner,
vs.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,
Respondent.

ON PETITION FOR WRIT OF CERTIORARI
TO THE CALIFORNIA SUPREME COURT

BRIEF OF REAL PARTY IN INTEREST INDEPENDENT ENERGY PRODUCERS ASSOCIATION IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

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QUESTION PRESENTED

Real Party in Interest Independent Energy Producers Association disagrees with petitioner's statement of the issue because it is based on a false premise. Petitioner Pacific Gas and Electric Company has not been required by the California Public Utilities Commission to pay prices in excess of those authorized by the Public Utility Regulatory Policies Act of 1978 and therefore the California Supreme Court's denial of the petition below was correct. Independent Energy Producers Association submits that a correct statement of the issue is as follows:

Did the California Supreme Court err in declining to substitute its judgement for the California Public Utilities Commission's determination of avoided cost pursuant to the Commission's federal mandate, and the Commission's enforcement of its own standard contract requirements implementing that federal mandate?

STATEMENT PURSUANT TO RULE 28.1 OF THE RULES OF THE SUPREME COURT

Independent Energy Producers Association is a non-profit trade association of qualifying facility developers whose membership is as follows:

Aero Vironment, Inc.

Altamont Energy Corporation

Amos & Andrews, Inc.

Arbutus Corporation

Arco Solar, Inc.

Association of California Energy Officials

Basic American Foods

Big Valley Lumber Co.

Brady, Matt, Esq.

California Almond Growers Exchange

Calpine Corporation

Castor, Jon

Catalyst Energy Development

Centennial Energy

Cogeneration Capital Associates

Cogeneration Service Bureau

Collins Pine Company

Commercial Union Capital Corporation

Continental Wind & Sunshine Company

Conversion Industries

Coram Energy Corporation

Core Ventures, Inc.
Corn Products
Corstar
Diamond Shamrock/Thermal Power Company
Downey, Brand, Seymour & Rohwer
Dow Chemical Company
Energy Conversion Industries
Energy International, Inc.
Fairhaven Power Company
Fluor Venture Group, Inc.
Forward Power & Energy Co., Inc.
Gas Recovery Systems
Geoproducts Corporation
Georgia-Pacific Corporation
Grattan, Gersick & Karp
Grueneich & Lowry
GWF Power Systems Company
Hawthorne Engine Systems
Helmbold & Stewart, Inc.
Henwood Associates, Inc.
Herzog Contracting Corp.
Howden Wind Parks, Inc.
Independent Hydro Developers
Independent Power Corp.
International Power Technology
JBS Energy, Inc.
Robert D. Kahn & Company

Koppers Company, Inc.
J. Laurain & Associates
Long Beach (The City Of)
Louisiana-Pacific Corp.
Luz Engineering Corp.
Marron Reid & Sheehy
Mega Renewables
Mill & Sulphur Creek Power Plant Partnership
Miller, Taylor O.
Morse, Richard, Weisenmiller & Associates, Inc.
National Energy Associates
Natural Resource Ventures
Nevada Irrigation District
Northwest Power Company, Inc.
O'Brien Energy Systems, Inc.
Pacific Lighting Energy Systems
Pacific Thermonetics, Inc.
Renewable Energy Ventures, Inc.
Renewable Resource Systems, Inc.
Roseburg Lumber Company
San Gorgonio Farms
Santa Fe Pacific Realty Corp.
Sierra Hydro, Inc.
Sierra Pacific Industries
Signal Environmental Systems, Inc.
Simpson Timber Company
Solar Center (The)

Solar Turbines, Inc.
Thermo Electron (Energy Div.)
Tosco Cogeneration, Inc.
Ultrapower, Inc.
University of California
U.S. Windpower
Verle A. Williams & Assoc. Inc.
Windmaster
Wood & Associates
Yanke Energy Inc.
Zond Systems, Inc.

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No. 87-178

IN THE

Supreme Court of the United States

October Term 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation,
Petitioner,

vs.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,
Respondent.

BRIEF OF REAL PARTY IN INTEREST INDEPENDENT ENERGY PRODUCERS ASSOCIATION IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

STATEMENT OF THE CASE

Contrary to petitioner's assertions, this is not a case where the respondent Public Utilities Commission of the State of California (Commission) ordered actions in violation of any federal statute, is not a case involving an important question of federal law and is not a case involving a conflict between state supreme courts. The

determinations by the Commission rested entirely on its enforcement of petitioner's obligation to purchase electric power from qualifying facilities[1] (QFs) at petitioner's avoided cost as determined by the Commission and reflected in Commission approved standard contracts.

The Commission is the state regulatory authority with ratemaking authority over public electric utilities, including petitioner. As such, the Commission is *required* under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C.A. §§796 and 824a-3 (PURPA) to implement and enforce rules of the Federal Energy Regulatory Commission (FERC) under which electric utilities are required to purchase electric power made available from QFs at a price equal to the utility's avoided cost.[2] *See*, 18 C.F.R. Part 292; 16 U.S.C.A. §824a-3(f).

In the exercise of its jurisdiction under PURPA and FERC rules, the Commission approved the development and use of standard contracts being a "complete transaction, including prices, interconnection requirements, and other relevant factors." Decision 82-01-103, 8 Cal.P.U.C.2d 20, 39. The prices contained in standard contracts constitute *by definition*, the utility's avoided cost, as pointed out by the Commission:

---

[1] A qualifying facility is a cogeneration or small power production facility meeting certain criteria respecting size, fuel use, non-utility ownership and efficiency which, on that basis, are exempt from most regulation under the Federal Power Act and state laws regulating electric utilities. *See*, 16 U.S.C.A. §§796(17) and (18); 18 C.F.R. 292.101(b)(1).

[2] " 'Avoided costs' means the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. §292.101(b)(6).

> "In adopting the parameters for rates that will be part of the standard offers, we are establishing a definition for a utility's avoided costs to be applied when purchasing energy from qualifying facilities under the terms and conditions of a specified standard contract." Decision 82-01-103, 8 Cal.P.U.C.2d 20, 40.

Thus the Commission, in the exercise of its jurisdiction and authority, has determined that payments made pursuant to a standard offer *constitute* payment of the purchasing utility's avoided cost. The Commission has therefore necessarily also determined that such payments may not be challenged because they differ from some other determination of avoided cost as proposed by petitioner.

Although the Commission was not constrained by FERC rules to utilize the standard contract approach, it was (and remains) constrained to implement the federal law in a manner calculated to "encourage" QF development. 16 U.S.C.A. §824a-3. This fact is important because the Commission has no jurisdiction to effect a basis for payment to QFs at less than the purchasing utility's full avoided cost.

> "On February 19, 1980, FERC issued its final rules implementing Section 210. These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere." Decision 82-01-103, 8 Cal.P.U.C.2d 20, Finding of Fact No. 7.

Aside from the fundamental fact that QFs are entitled to receive full avoided cost, QFs are also entitled to select one of two bases upon which those costs are determined. At the QF's sole election, avoided cost may be determined at the time the QF's power is delivered, or determined in advance

at the time the obligation is made to deliver power, for deliveries to occur in the future. 18 C.F.R. §292.304(a). Accordingly, in Decision 82-01-103 the Commission ordered the development of both "short run" (avoided cost payments determined from time to time) and "long run" (avoided cost payments forecasted in advance) standard contracts. Decision 82-01-103, 8 Cal.P.U.C.2d 20, 41-42.

The standard contracts in the case at bench, designated by the Commission as "Interim Standard Offer 4," are long-run contracts and thus require petitioner to make payments which are calculated at the time the contract was executed for "energy," "firm capacity" and "as-available capacity"[3] to be delivered in the future. Decision 83-09-054; Appendix to Petition, p. A-2. These payments are equal by definition to petitioner's long-run avoided cost. Decision 82-01-103, 8 Cal.P.U.C.2d 20, 40.

The contracts in the case at bar were executed by petitioner and individual QFs in 1985 and allow the QF five years within which to commence operation. The contracts provide that the QF shall receive a fixed firm capacity payment based on the year the QF achieves firm operation and fixed energy and as-available capacity payments for the first ten years of operation.

---

[3] Electric power consists of both energy and capacity. Energy is measured in kilowatt-hours and is what makes electric equipment work. A utility's avoided cost of energy consists of the variable costs (fuel, operation, maintenance, etc.) of producing a kilowatt-hour. Capacity is measured in kilowatts and is the capability of producing energy. A utility's avoided cost of capacity consists of the capital costs of a generating facility capable of producing energy. Capacity is "firm" if generating capability is assured during peak consumption periods. Capacity is "as-available" if the timing of generating capability is not so assured due to uncertain fuel availability, equipment outages or inability or unwillingness of the QF to contractually commit to a firm capacity obligation.

The case below arose out of petitioner's failure to make available to the Real Parties in Interest an Interim Standard Offer 4 contract containing pricing provisions meeting the criteria of the Commission's order approving the contract. In particular, although such contracts were entered into in 1985 (and thus contemplated QFs becoming operational as late as 1990), petitioner failed to provide a firm capacity price for operation dates after 1987. Petitioner also failed to provide forecasted energy and as-available capacity values for years after 1997 although Interim Standard Offer 4, both by Commission orders and its own provisions, requires the payment of such forecasted prices for the first ten years of operation. As a result of petitioner's dereliction, Real Parties in Interest asked the Commission for an order that petitioner complete these price schedules.

In a series of decisions, the Commission determined that its prior orders and the contracts (1) require petitioner to establish a payment schedule for firm capacity calculated for the term of the contract at the time the contractual obligation was incurred (Decision 86-10-038, Finding of Fact No. 4; Appendix to Petition, p. A-137), (2) entitle the QF to have that firm capacity price based on the date of initial firm capacity availability (Decision 86-12-013, Conclusion of Law; Appendix to Petition, p. A-144), and (3) guarantee up to ten years of energy and as-available capacity price certainty (Decision 86-10-038, Finding of Fact No. 6; Appendix to Petition, pp. A-147, 148).

In denying the petition below without comment, the California Supreme Court necessarily determined that in acting as it did the Commission acted in the regular pursuit of its authority. Cal. Pub. Util. Code §1757; *Goldin v. Public Utilities Commission*, 23 Cal.3d 638, 592 P.2d 289 (1979). There is no substantial federal question or any federal question at all. The California Supreme Court did not err in declining to substitute its judgment for the Commission's

determination of petitioner's avoided cost and enforcement of its own orders.

REASONS WHY A WRIT OF CERTIORARI SHOULD NOT BE ISSUED

I

A Writ of Certiorari Should Not Be Issued Because There Is No Federal Question In That Petitioner Has Not Been Required To Make Payments To Qualifying Facilities In Excess Of Avoided Cost.

Contrary to petitioner's contention, the case at bar does not involve a determination that petitioner should or must make payments to QFs in excess of avoided cost and, therefore, does not involve the scope of the Commission's authority under PURPA, FERC rules or any other federal law or statute. Instead, the case at bar merely involves an order of the Commission, consistent with federal law, that petitioner come into compliance with the terms of a Commission order and approved standard contract under which petitioner was required and agreed to pay QFs based on petitioner's long-run avoided cost.

Petitioner acknowledges (Petition, p. 19) that FERC rules require that QF power sold under a fixed term agreement be priced at avoided cost calculated *either* at the time of delivery or at the time the power purchase agreement is executed, and that the election between those alternatives is at the QF's sole option. The standard contracts in the case at bar were approved by the Commission for use by QFs making the election to be paid avoided cost calculated at the time the power purchase agreement is executed, referred to as the long-run avoided cost. "Interim Standard Offer No.

4 was our first attempt to implement power purchase contracts based on utilities' *long-run avoided costs.*" Decision 86-10-038; Appendix to Petition, p. A-128. The determination of long-run avoided cost necessarily involves the use of projections and "the same sort of planning (such as lengthy forecasts of the purchasing utility's resource mix and costs) that goes into a utility decision to build a new power plant." *Id.* p. A-129.

Petitioner erroneously contends that the Commission ordered petitioner to make payments in excess of avoided cost, claiming that it "showed that the prices greatly exceed the current forecasts of the value of additional, not yet operational resources." Petition, p. 19. In fact, petitioner states no basis for concluding, and there has been no determination, that its current forecasts are more accurate than the forecasts used by the Commission. As the Commission stated, petitioner's allegation would require a "crystal ball." Decision 86-10-038; Appendix to Petition, p. A-127. Petitioner's contention is a *non sequitur* in any event because a comparison of the Commission approved long-run avoided cost applicable to the contracts in the case at bar (reflecting expectations at the time the contracts were executed) with petitioner's current estimates of long-run avoided cost is simply not relevant because the question whether the Commission approved prices exceed petitioner's avoided cost at the time of delivery is likewise not relevant. FERC's rules expressly provide as much:

> "In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate PURPA or the FERC rules if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. 292.304(b)(5).

Unlike all other utilities subject to the Commission's order,[4] petitioner's forecasted price schedules did not consider all the years when qualifying facilities signing contracts might permissibly come on-line pursuant to those contracts. *See*, D.86-10-038, Appendix to Petition, p. A-129. It was therefore necessary and proper for the Commission to order the completion of petitioner's forecasted price schedules.

The Commission's determination to order petitioner to complete the forecasted price schedules was clearly correct and required to give effect to the clear meaning and purpose of the contracts. That determination was clearly correct with respect to the firm capacity forecasted price schedule because the contracts provide that the QF's on-line date may occur any time within five years of execution and it is apparent that forecasted firm capacity price values must be stated for each of those five years in order to effectuate the contract. The Commission's determination with respect to the energy and as-available capacity forecasted price schedules was clearly correct because the contract defines the "fixed price period" as "[t]he period during which forecasted or levelized energy prices, and/or forecasted as-delivered capacity prices, are in effect" and "the first ten years of the term of agreement if the term of agreement is anywhere from 20 through 30 years." Appendix to Petition, p. A-197.

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[4] Petitioner is one of three California utilities which were required to execute Interim Standard Offer 4 contracts with QFs. Because the other two, Southern California Edison Company and San Diego Gas & Electric Company, maintained forecasted prices of adequate duration to effectuate their contracts and comply with the Commission orders, only petitioner Pacific Gas and Electric Company was involved in the case below.

Therefore, in ordering petitioner to complete the forecasted price schedules the Commission did not amend any contract and did not require petitioner to pay QFs a price different from its best estimation of petitioner's long-run avoided cost. Since the Commission's action was required under PURPA and the FERC rules its action necessarily is not violative of these federal mandates as petitioner contends, and therefore no federal question is involved in this case.

II

A Writ Of Certiorari Should Not Be Issued Because The Case At Bar Does Not Involve Or Promise To Resolve A Conflict Among Different Courts As To The Proper Interpretation Of PURPA Or Any Other Matter Of Interest To This Court.

Petitioner erroneously contends that the case at bar raises an important federal issue that is national in scope based on an alleged conflict created by two state court decisions interpreting PURPA. The cases cited as conflicting by petitioner are *Kansas City Power & Light Co. v. State Corp. Commission*, 234 Kan. 1052, 676 P.2d 764 (1984) *and Consolidated Edison Co. v. Public Service Commission*, 63 N.Y.2d 424, 472 N.E.2d 981 (1984), appeal dismissed, 470 U.S. 1075 (1985). Contrary to petitioner's contention, these cases do not even conflict with each other and the case at bar does not conflict with either.

Consolidated Edison considered the question whether PURPA preempts states from legislating a minimum purchase price from QFs rather than a variable avoided cost rate. The Court of Appeals of New York held that PURPA does not preempt the state legislature from requiring

electric utilities to pay for energy from qualifying facilities at a rate greater than those electric utilities' avoided cost, a determination which this Court refused to upset.

Kansas, in contrast, did not involve a statute similar to New York but dealt with a state Commission's authority to decline to enforce the FERC rules in favor of its own determination of appropriate rates for purchases from qualifying facilities. The Kansas Corporations Commission declined to establish avoided cost, in favor of an alternative state basis for establishing the prices which utilities must pay for power from qualifying facilities. The *Kansas* court concluded that the Kansas Commission was required by PURPA and the FERC regulations to set rates for the purchase of power from qualifying facilities based on the utility's avoided cost.

Consolidated Edison and *Kansas* are not factually similar and are not in conflict at all.

Petitioner's suggested conflict between *Kansas* or *Consolidated Edison* and the case at bench is also without merit because, unlike the case at bench, *Consolidated Edison* and *Kansas* each involved an affirmative determination to require utilities to pay greater than avoided cost. While petitioner compares certain California statutes with the situation in both New York and Kansas, it fails to point out that in the case at bench there has been no determination to require petitioner to pay more than avoided cost and that the decisions below are devoid of any reference to any authority to establish rates different from avoided cost. Thus, petitioner's statement of the issue is hypothetical. As petitioner points out, "it [the Commission] has never defined 'equitable rates' as anything other than 'avoided cost' " and the Commission "chose avoided cost as the standard to be applied in California" and, petitioner concludes, "the Commission has never attempted to deviate

from that standard, even in authorizing interim SO4." Petition, p. 18.

Thus, whatever independent state authority the Commission may have, petitioner's general allegations are defeated by its own argument since the Commission's actions consisted entirely of the establishment of petitioner's long-run avoided cost and the enforcement of petitioner's obligation to pay those prices to QFs under the contracts and numerous prior Commission decisions implementing PURPA and the FERC rules. Unlike *Consolidated Edison* there has been no invocation of a state authority independent of PURPA and the FERC rules. Unlike *Kansas* there has been no determination by the Commission to eschew its obligations under PURPA and the FERC rules. Unlike both *Consolidated Edison* and *Kansas* there has been no determination that petitioner must pay any amount other than its avoided cost. There is therefore no conflict with decisions of other courts and there is no federal question supporting this petition.

III

CONCLUSION

The determination of the California Supreme Court to decline petitioner's bid to review the decisions of the California Public Utilities Commission enforcing petitioner's obligations under PURPA, FERC rules and Commission approved contracts and orders, is correct. Furthermore, contrary to petitioner's contention, the decision of the California Supreme Court does not involve a question of federal law and does not conflict with any decision of any other state's highest court. A writ of

certiorari should therefore not be issued and the Petition for Writ of Certiorari should be denied.

Respectfully submitted,

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Supreme Court, U.S.
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No. 87-178

IN THE

Supreme Court of the United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California corporation,
Petitioner,

vs.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,
Respondent.

BRIEF OF RESPONDENTS ULTRAPOWER, INC., AND GWF POWER SYSTEMS COMPANY IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

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QUESTION PRESENTED

Respondents Ultrapower, Inc., and GWF Power Systems Company ("these Respondents") disagree with Petitioner's statement of the question presented. Petitioner's statement of the question assumes a fact not borne out by the evidentiary record, *i.e.*, that the prices Petitioner was ordered to pay were in excess of those permitted by the Public Utility Regulatory Policies Act of 1978. A proper statement of the question presented should be:

Did the California Supreme Court err when it declined to review a factual determination made by the California Public Utilities Commission pursuant to federal and state law?

THE PARTIES TO THIS PROCEEDING

The designation of the "Parties to this Proceeding" pursuant to Rule 21.1(b) contained in the Petition for Writ of Certiorari accurately sets forth those entities which submitted either the Petition for Writ of Review or Answers below to the California Supreme Court. The listing, however, does not include all of the entities who were entitled to notice of the proceedings before the California Supreme Court. Those entities include the following: Southern California Edison Company; San Diego Gas & Electric Company; Independent Power Corporation; Pacific Lighting Energy Systems; California Energy Commission; University of California; U.S. Wind Power, Inc.; Foster Wheeler Power Systems, Inc.; Howden Wind Parks, Inc.; BHC Inc.; California Cogeneration Council; Henwood Energy Systems, Inc.; Caterpillar Capital Company, Inc.; KKE & Associates; Pacesetter Energy Development; Waste Management of North America, Inc.; Water Energy Resource Consulting; Cogeneration Service Bureau; Trigen Energy; Bechtel Corporation; Pacific Hydro Power; Energy Factors; and MRW, Inc.

In addition to the entities listed above, the following entities also appeared before the California Public Utilities Commission on its approval of Interim Standard Offer No. 4 (which has been placed into issue by Petitioner herein): Geothermal Generation, Inc.; Pillsbury, Madison, & Sutro; Occidental Geothermal, Inc.; Herzog Contracting Corporation; San Diego Energy Recovery Project; McDonnell Douglas; University Energy; Resource Management International, Inc.; Toward Utility Rate Normalization; Independent Energy

Producers Association; Tosco Corporation; Applied Power Technology, Inc.; California Solid Waste Management Board; Sierra Energy and Risk Assessment; Natural Resource Defense Council; Natomas Company; California Manufacturers Association; California Hydro Systems, Inc.; Energy Consulting Group; Arco Solar, Inc.; Brown, Vence & Associates; Ebasco Services, Inc.; Thermonetics, Inc.; Sigma Group; Union Oil Company of California; Federal Paper Board, Inc.; Stanford University; American Energy Projects, Inc.; Stauffer Chemical Company; West County Agency; General Electric Company; Stone & Webster; Reed V. Schmidt; and Norman Ross Burgess. In addition to these entities, there may be others who also have standing as real parties in interest by virtue of the fact that such entities have contracted with Petitioner Pacific Gas & Electric Company under Interim Standard Offer No. 4. These Respondents, however, are currently unaware of the identity of such entities.

The following is provided pursuant to Rule 28.1. Respondent Ultrapower, Inc., is a wholly owned subsidiary of Ultrasystems Power and Environmental Systems, Inc., which in turn is a wholly owned subsidiary of Ultrasystems, Inc. The only subsidiary (other than wholly owned subsidiaries) and affiliate of Ultrasystems, Inc., is Micro Cogen Systems, Inc. Ultrasystems, Inc., owns 80% of the stock of Micro Cogen Systems, Inc. Respondent GWF Power Systems Company is a wholly owned subsidiary of Allied-Signal, Inc. Allied-Signal, Inc., has no subsidiaries or affiliates other than wholly owned subsidiaries. Allied-Signal, Inc., has entered into an agreement to sell 100% of the stock of GWF Power Systems Company to National Energy Partners, a partnership. To the

understanding of GWF Power Systems Company, CEA, Inc., owns 50% of the partnership interest in National Energy Partners and Harbart Contruction Company owns the other 50%. CEA, Inc., in turn is a wholly owned subsidiary of Public Service Corporation of New Jersey, a public utility. GWF Power Systems Company is not aware of any affiliate or subsidiary of Public Service Corporation of New Jersey other than CEA, Inc., and is not aware of any affiliate or subsidiary of Harbart Construction Company.

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IN THE

Supreme Court of the United States

OCTOBER TERM, 1987

No. 87-178

PACIFIC GAS AND ELECTRIC COMPANY,
a California corporation,

Petitioner,

vs.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,

Respondent.

BRIEF OF RESPONDENTS ULTRAPOWER, INC., AND GWF POWER SYSTEMS COMPANY IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

Respondents Ultrapower, Inc. ("Ultrapower"), and GWF Power Systems Company ("GWF") respectfully submit this brief in opposition to the Petition by Pacific Gas & Electric Company ("PG&E") for a Writ of Certiorari.

STATEMENT OF THE CASE

PG&E asks this Court to review three electricity pricing decisions made by the California Public Utilities Commission (the "PUC" or the "Commission")

regarding the interpretation of a negotiated standard contract, Interim Standard Offer No. 4 ("SO4"), notwithstanding that these decisions were founded on years of Commission investigations, hearings, and negotiations with all affected parties. PG&E improperly requests that this Court substitute its judgment for that of the PUC and find that the Commission improperly weighed and balanced the policy considerations and evidence that underlie the decisions at issue.

For almost a decade the PUC has been investigating how properly to encourage the development of qualifying facilities[1] ("QFs") as alternatives to traditional petroleum and nuclear based power plants. These years of investigation developed most of the data and formulae used in SO4.

The process of developing SO4 began with Order Instituting Rulemaking No. 2 ("OIR 2"), issued by the PUC on September 3, 1980. OIR 2 initiated proceedings "for the purpose of establishing standards governing the prices, terms and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities." PUC Decision 82-01-103 (App., p. A-8). These proceedings included many Commission hearings, the acceptance by the Commission of public comments and petitions from utilities and QFs, several PUC staff reports, and a number of administrative law judge rulings. *Id.* (App., pp. A-8-9). The proceedings re-

[1] A "qualifying facility" is defined to be a cogeneration facility (*i.e.*, one which produces electricity and useful forms of thermal energy) or a small power production facility meeting certain criteria regarding size, fuel-use efficiency, and non-utility ownership. 18 C.F.R. §§ 292.101(b)(1), 292.202(c) (1986) (unless indicated, all references are to the 1986 version of the regulations).

sulted in two important PUC decisions in 1982: Decision 82-01-103 (App., p. A-1), issued on January 21, 1982, and Decision 82-12-120 (App., p. A-162), issued on December 30, 1982.

Decision 82-01-103 established two elements of a program to encourage the development of QFs. The first element was the standard offer system itself. Both the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and California law require that utilities purchase electricity produced by QFs pursuant to terms set by the PUC. The PUC elected to establish such terms through the standard offer system. Under this system, standard contracts written by utilities are approved by the PUC. QFs can then sign a standard offer without further PUC review and any purchase by a utility pursuant to a standard offer is deemed *per se* reasonable. (App., p. A-27.) Decision 82-01-103 created this standard offer approach, and ordered the utilities to draft the initial standard offers pursuant to detailed instructions from the Commission regarding the provisions the standard offers should contain. Included in this Order was a description of what proved to be the prototype for SO4. (App., p. A-146.)

The second element set by Decision 82-01-103 was that pricing of electricity produced by QFs under these standard offers was to be based on PURPA's definition of "avoided costs," *i.e.*, the costs that the utilities would incur if they had to acquire the electricity from some source other than a QF or had to generate it themselves. (App., p. A-91.) *See* 18 C.F.R. § 292.101(b)(6). The PUC found that total avoided costs are made up of two elements: (1) "capacity costs," which are essentially the costs a utility incurs

to insure that it has enough capacity to always be able to provide sufficient electricity to its customers; and (2) "energy costs," which are the marginal costs of producing electricity and which consist mainly of the fuel the utilities would have to purchase to produce the electricity if it was not available from QFs. (App., pp. A-29-30.) The Commission decided that *all* standard offers would include pricing provisions based on these energy and capacity "components" to avoided costs.

Subsequently, in Decision 82-12-120, the Commission determined that the capacity component of avoided costs to a utility ("avoided capacity costs") was to be based on the cost of a combustion turbine. (App., pp. A-235-36, 285.) In that decision the Commission also determined that QFs should be provided a contract for the sale of capacity on a firm basis over a period of 30 years at a price equal to the utility's levelized avoided capacity costs. The specific figures to be used in calculating these costs were also approved by the Commission in Decision 82-12-120. (App., pp. A-294-95.)

One of the results of Decision 82-12-120 was the creation of Standard Offer No. 2 ("SO2"). SO2 included prices for as-available and firm capacity payments.[2] SO2 also included the methodology for calculating the energy prices which a QF signing that standard contract would receive. The energy prices

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[2] "Capacity" is measured in kilowatts and is the capability of producing energy. Capacity is "firm" if generating capability is assured during peak consumption periods. Capacity is "as-available" if the timing of generating capability is not so assured due to uncertain fuel availability, equipment outages, or inability or unwillingness of the QF to contractually commit to a firm capacity obligation.

were, however, subject to adjustments for variations in actual avoided costs which might occur during the term of that contract.

Shortly after SO2 was approved by Decision 82-12-120, it became apparent that there was a lack of certainty in its energy pricing provisions. Energy prices were subject to short term swings in avoided costs during the term of SO2, causing significant financing difficulties for QFs. The primary problem, recognized even by PG&E, was that lenders would not provide the necessary capital to finance a QF without a fixed income statement projection for the facility, which of course required fixed prices. Decision 83-05-038 (App., pp. A-306-07); Decision 83-09-054 (Pet. App., p. A-4). As a consequence, the PUC elected to begin work on a new standard offer which would in many ways be identical to SO2, but would also provide for fixed energy prices by making long term estimates of avoided costs which the parties would agree to honor regardless of fluctuations in actual avoided costs during the term of the contract.

The procedure the Commission selected for the preparation of the new standard offer was a negotiating conference. During this negotiating conference, representatives of the utilities, QFs, the Commission's staff, and an administrative law judge would attempt to agree on the terms of the new standard offer contract. Decision 83-05-038 (App., p. A-310). The conference was held for five weeks during the months of May and June, 1983, and resulted in an agreement among the parties on the fundamental provisions of the new contract, SO4. The utilities each then drafted their version of the contract, and submitted them to the PUC for approval. In Decision

83-09-054, issued in September of 1983, the Commission approved PG&E's version of SO4. Decision 83-09-054 (Pet. App., pp. A-44-45).

One major new feature of SO4 was the "fixed energy price" option. Under this concept, a QF could elect to have the first ten years of energy payments fixed. The estimates provided by the utilities for avoided energy costs would be guaranteed to the QF regardless of fluctuations in fuel costs during those first ten years of SO4. After the first ten years, energy prices would be allowed to fluctuate with actual, short term avoided energy costs. (Pet. App., pp. A-189, 210.) With regard to firm capacity, the parties agreed to incorporate the pricing methodology and assumptions utilized in calculating firm capacity prices that existed for SO2 contracts at the time SO4 was negotiated. As was the case in SO2 for firm capacity, annual capacity numbers under SO4 would be calculated for the entire term of the contract, those prices would then be levelized, and the QF would receive the levelized payment established for each year of SO4 as its firm capacity price. (Pet. App., pp. A-191, 234-40.) *See also* Decision 83-09-054 (Pet. App., p. A-22); Decision 85-04-075 (Pet. App., pp. A-101-02); Decision 86-10-038 (Pet. App., p. A-137). The "firm capacity" price schedule for SO4 was set out in Table E-2 (Pet. App., p. A-238) *or its successor* (*whichever was higher*), and SO4 specifically imposed on PG&E the duty to periodically publish a "schedule of the $/kw-year prices" that it offered to pay for firm capacity. (Pet. App., p. A-197.)

Another vital feature of SO4, as it was in SO2, is the provision in Article 12 allowing a QF *up to five years* from the date the contract is executed *to begin*

delivering energy to the utility. As a result, a QF signing SO4 in 1983 would have until 1988 to build its plant and commence energy deliveries (not 1987 as suggested by PG&E). (Pet. App., p. A-197.) In approving SO4, the Commission determined that it would remain in effect and available for execution "for at least six months, and until further order." Decision 83-09-054 (Pet. App., p. A-44). This period ultimately ended on April 17, 1985, when the Commission suspended SO4 in deference to a final version of the contract which was the subject of new Commission proceedings. Decision 85-04-075 (Pet. App., p. A-61).

Taken together, these time parameters mean that a QF could execute SO4 as late as April 1985 and would have *until April 1990* to begin delivering energy (again, not 1987 as urged by PG&E). To be complete, any SO4 executed in 1985 would need firm capacity prices based on energy delivery commencement dates through 1990 and fixed energy prices for up to and including all of a ten year period beginning in 1990, or *through year 2000* (not 1997 as contended by PG&E). This was recognized by the 1983 PUC decision that approved SO4: "The QF project must be on line *within 5 years* from the date the agreement is executed. However, the QF agrees to the payment stream, based on the forecast, when the contract is signed. This means utilities *must* have a *15-year* forecast *when the contract is signed* to allow for a maximum *five-year* hiatus before operation and payments start after execution." Decision 83-09-054 (Pet. App., p. A-19) (emphasis added).

At the time SO4 was approved by the PUC, it was everyone's understanding and expectation that the *estimates* which were agreed to as fixed prices would,

to some extent, turn out to be inaccurate; it was anticipated that actual, short-term avoided costs from time to time would vary from the estimates. However, for purposes of certainty, all parties accepted the risk that the estimates would be higher or lower than actual avoided costs at any given point in time in the future. Thus, Article 2 of SO4 states that "[a]ctual avoided costs at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this agreement." (Pet. App., p. A-187.) At the time SO4 was approved, none of the utilities appealed or protested any of the pricing determinations made by the PUC.

After the approval of SO4 by the PUC, the utilities each issued their own version of that contract; but in each instance the capacity and energy tables were incomplete. For example, in PG&E's version of SO4 the energy price schedule (Table B-1) ended in 1997, not 2000, and the firm capacity table (Table E-2) ended in 1987 instead of 1990. (Pet. App., pp. A-210, 238.)

While this problem was raised in advance in some instances, many SO4s were signed with incomplete tables. Quite simply, some QFs did not focus on the problem at the time; others relied on the good faith of PG&E to comply with the provisions of SO4 to later update its pricing tables.[3] In any event, the problem came to a head in 1986 when the QFs who had signed such contracts approached the two main utilities involved, Southern California Edison and PG&E,

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[3] PG&E has a specific duty of good faith imposed on it in negotiating and interpreting SO4. Decision 82-01-103 (App., p. A-149).

to update the pricing tables. Southern California Edison quickly resolved the problem by extending the tables for the necessary number of years using the already established formulae. PG&E, however, refused to perform this contractually mandated and ministerial act, contending that it had no obligation to do so despite the fact that the entire pricing scheme, which had been developed during the five week negotiating conference, would not work without complete tables.

PG&E had no excuse for not completing these tables. In October 1985, just a few months before PG&E refused to extend the SO4 tables, it filed an application with the PUC requesting the Commission's approval of the extension of *the exact same tables* in SO2. (As noted above, the firm capacity pricing scheme used in SO4 is *identical* to that which was approved in 1982 for SO2.) At this time, the same problem of incomplete tables was being encountered with SO2, but PG&E took a different position on that issue due to its desire to execute more of the SO2 variable price agreements. For SO2, PG&E merely submitted an extended firm capacity price table to the Commission for its approval, which PG&E calculated using the existing formulae. PG&E's application states that extension of the table was "merely . . . a ministerial act." (App., p. A-318.) *Thus, at approximately the same time that PG&E contended it had no obligation under SO4 to extend the price tables, it was affirmatively seeking PUC permission to update the identical price tables in SO2 as merely ministerial.*

Some of the QFs who executed SO4 realized, at the time of execution, that the firm capacity and en-

ergy price tables being provided by the utilities were incomplete. PG&E responded to these individual QFs who focused on the problem by completing the tables in their specific versions of SO4, using the long-established formulae and data. *See* the Response of Foster Wheeler Power Systems, Inc., to Pacific Gas & Electric Company's Application for Rehearing of Decision 86-10-038 (App., p. A-320). There was no need for PG&E to seek further guidance or instructions from the PUC on how to complete the tables for the objecting QFs since all parties were familiar with the calculations and the relevant factors had been set and quantified since 1982. PG&E, however, failed to inform a single, nonobjecting QF of this problem, notwithstanding that other QFs had brought this issue to PG&E's attention.

After PG&E refused to extend the SO4 tables for the remaining QFs, the QFs who were affected by PG&E's refusal petitioned the PUC for an order that the tables be extended. The QFs pointed out that SO4 itself requires complete tables and that the methodology and formulae were already in place to allow the extension of the tables just as if complete tables had been provided in 1983.

The PUC agreed with the QFs, and, in the three decisions at issue here, Decisions 86-10-038, 86-12-013, and 86-12-104, required that PG&E complete the price tables. No such orders were necessary for Southern California Edison as it had already recognized the need to complete the tables and had done so. In the case of firm capacity prices, the PUC ordered that the tables be completed using the same methodology and factors which were used to generate the tables in 1983, *the same approach which had been*

in place ever since the Commission first resolved the capacity pricing issue in 1982. As the Commission explained, the "table is merely an expression of the values of the agreed-upon price proxy, the cost of a combustion turbine (CT), carried over all applicable years. The change due to escalation was thereby made merely ministerial." Decision 86-12-104 (Pet. App., p. A-146).

In the case of energy prices, however, the prices were based on PG&E's own fuel cost estimates and the negotiations of the parties in 1983. The Commission thus felt it unfair to increase the energy prices for the years which had to be added to the tables despite the fact that the tables established in 1983 showed an increase in costs each year. (Pet. App., pp. A-146-47.) Therefore, the Commission simply ordered that the energy price number for the year 1997, the last year of the table written in 1983, be used for the years 1998, 1999, and 2000. (Pet. App., p. A-147.) *In support of these orders, the Commission made findings of fact that the parties to SO4 intended that complete tables be provided so that the pricing provisions of the contract would function as intended, and that completion of the tables was merely a ministerial act which could be performed with the existing formulae.* Decision 86-10-038 (Pet. App., p. A-137); Decision 86-12-104 (Pet. App., pp. A-147-48).

On November 5, 1986, PG&E complied with Decision 86-10-038 by completing the firm capacity price schedule for SO4 without any further guidance or instructions from the Commission, thus again establishing the ministerial nature of the extension. Indeed, in the case of the firm capacity table (Table E-2), all PG&E had to do was extend for three years the table

that it wrote in 1983 using the escalation factors established by the Commission in 1982. For the energy price and as delivered capacity tables, PG&E merely followed the Commission's orders to include the same prices already in the tables for 1997 for the years 1998, 1999, and 2000.

On January 26, 1987, PG&E instituted an original proceeding before the California Supreme Court and filed its petition for a writ of review. Pursuant to Section 1758 of the California Public Utilities Code and Rule 58 of the California Rules of Court, Ultrapower and GWF timely answered that petition. The California Supreme Court summarily denied PG&E's petition on April 29, 1987.

SUMMARY OF ARGUMENT

Despite PG&E's attempt to unduly complicate this matter with various red herrings, the issues truly before the Court are straightforward and not particularly difficult.[4] This Court should deny PG&E's petition because it simply does not present a substantial federal question. Contrary to PG&E's claim that this case raises the issue of what PURPA re-

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[4] For example, the petition includes an entirely unsupported claim that, based on "current" estimates, the prices fixed by SO4 may exceed, all qualifying facilities considered, "actual" avoided costs by $1 billion. Petition, at 2. PG&E's contention borders on the absurd. The prices in SO4 were derived after extensive negotiations by all parties. There is no reason to believe that those numbers, agreed to and approved in 1983, are any less accurate than PG&E's current estimates. PG&E's "current estimate" of future avoided costs may change tomorrow depending, for example, on what events transpire in the Middle East.

quires in the absence of state authority on the pricing of QF power, this case involves only issues of fact and the interpretation of state law, an area ill suited for review by this Court. Furthermore, even if the Commission erred in its conclusion that the extensions in the SO4 price tables represented avoided costs as defined by PURPA (a fact question), this Court has decided that PURPA expressly authorizes the states to require utilities to pay for QF power on a basis other than avoided costs. Thus, the only issue would be whether California law permits such a result. This Court should not be tempted to render an advisory opinion as to whether California law should be interpreted, as a matter of that state's law, to authorize prices differing from avoided costs. The petition should be summarily denied.

ARGUMENT

PG&E's contention that the Commission's orders forcing PG&E to abide by the contractual obligations contained in SO4 violates PURPA is premised on the notion that the price table extensions ordered by the Commission do not represent prices based on current estimates of future "avoided costs." PG&E's PURPA argument suffers from three fatal flaws.

First, although PG&E acknowledges that the prices set forth in SO4 were *negotiated* by the parties to that contract, it ignores the fact that the regulations issued by the Federal Energy Regulatory Commission ("FERC") implementing PURPA expressly permit the parties to negotiate prices that differ from or even exceed actual avoided costs. As a result, all the Commission did in this case was resolve a very fact specific contractual dispute as to the intent of the parties

who negotiated those prices; the requirements of PURPA did not come into play at all.

Second, the negotiated prices set forth in SO4 represented the parties' best attempt to forecast long term avoided costs at the time PG&E's obligation to purchase that power was incurred. The FERC regulations expressly provide that the parties may set prices based on predictions of long term avoided costs, and the parties are not required to adjust those contractually set prices with every fluctuation in energy costs. That is precisely what the parties did in SO4. Whether the cost predictions in SO4 are avoided costs as defined in the FERC regulations or are otherwise reasonable is a question of fact within the PUC's jurisdiction.

Third, even if the prices set forth in SO4 exceeded the parties' estimates of long term avoided costs (which they do not), and even if the prices contained in SO4 did not result from negotiation (although they clearly did), the Commission could still order PG&E to pay those prices because the Commission is authorized to do so by a specific California statute, and this Court has held that such state statutes are not preempted by PURPA. Therefore, even if the Commission erred in resolving the contractual issue, and even if the negotiated prices do not accurately forecast future avoided costs, the PUC's actions do not violate any federal statute or regulation and therefore do not raise a substantial federal question.

I. PURPA Permits PG&E and Qualified Facilities to Agree on Prices Which Differ from Avoided Costs.

PG&E's PURPA argument ignores the fundamental fact that SO4 was the result of negotiations between

the utilities and QFs. Under FERC's regulations implementing PURPA, utilities and QFs are absolutely free to negotiate rates different from avoided costs:

> *Negotiated rates or terms.* Nothing in this subpart: (1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms and conditions relating to any purchase, *which differ from the rate or terms or conditions which would otherwise be required by this subpart.*

18 C.F.R. § 292.301(b)(1) (emphasis added and in original); *see also American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402 (1983) (holding FERC regulations permit parties to negotiate prices other than full avoided costs if consistent with policies of PURPA).

PG&E's argument that the prices added to the tables do not reflect PG&E's estimates of future avoided costs completely ignores this basic regulatory exception to PURPA's avoided cost rules. PG&E knew at the time it agreed to SO4 that the prices set forth therein would almost certainly either exceed or be below actual avoided costs at time of delivery. "The prices to be paid [to a QF] for energy and/or capacity delivered pursuant to [SO4] have wholly or partly been fixed at the time of execution. Actual avoided costs at the time of energy and/or capacity deliveries may be *substantially above or below the prices fixed in* [*SO4*]." SO4 (Pet. App., p. A-187) (emphasis added).

Thus, PG&E cannot argue in good faith that PURPA disallows the Commission's decision, based on a fact specific interpretation of contract negotia-

tions, that SO4 should contain the prices negotiated by the parties regardless of fluctuations in avoided cost projections that have occurred since SO4 was approved. Indeed, the very basis for SO4 was the notion that the parties would commit to fixed prices that would not be subject to alterations based on short term avoided cost swings, *an approach expressly authorized by the FERC regulations implementing PURPA*.

The correctness of the fact specific conclusions reached by the PUC when it resolved the parties' contract dispute is not a proper question for this Court's review. This Court has repeatedly refused to review specific factual findings underlying contract actions. "The Supreme Court will usually deny certiorari when review is sought of a lower court decision which turns solely upon an analysis of the particular facts involved, *or upon the construction of particular contracts or written instruments.*" R. Stern, E. Gressman & S. Shapiro, Supreme Court Practice § 4.14 (6th ed. 1986) (emphasis added). Moreover, even when a petition for a writ of certiorari claims that "the cause involved [is] a grave question of vital importance to the public," if that "grave question" involves a question of fact, the Court is generally not moved to grant certiorari. *Southern Power Co. v. North Carolina Public Service Co.*, 263 U.S. 508, 509 (1923).

The Court is even more hesitant to grant certiorari when the findings of fact that it is asked to review involve those of a state administrative agency. *Black v. Cutter Laboratories*, 351 U.S. 292, 298 (1955). "[A] state may enunciate policy through an administrative agency, as well as through its Courts, and so long

as there is an opportunity for judicial review the fact that such review may be denied on a discretionary basis does not make the agency's action any less the voice of the state for purposes of this Court's jurisdiction or for purposes of federal-state comity." *Pacific Telephone and Telegraph Co. v. Public Utilities Commission*, 443 U.S. 1301, 1304 (1979) (Rehnquist, J., opinion in chambers).

Under California law, that state's policy may be applied by the PUC, subject to discretionary review by the California Supreme Court. *See* Cal. Pub. Util. Code §§ 1757, 2821 (West 1975 & Supp. 1987, respectively). PG&E is complaining that, under California law, the evidentiary record before the PUC was not sufficient to permit the Commission to issue its three 1986 decisions. However, the best judges of the sufficiency of that record are the PUC and the California Supreme Court. Since the PUC and the California Supreme Court have already judged this matter, this Court should not waste its resources revisiting the question of the sufficiency of an evidentiary record under state law.

II. The Commission's 1986 Decisions Represent an Interpretation of the Parties' Best Estimates of Future Avoided Costs.

In issuing its three challenged decisions, the PUC relied on the vast evidentiary record created since 1980 relating to OIR 2 and the parties' intent in 1983. According to PG&E, when the dispute over the completion of the SO4 tables arose in 1986, the Commission was required to ignore this evidentiary background and to rely solely on 1986 data to determine whether the prices to be added to the tables were valid estimates of PG&E's future avoided costs.

Essentially, PG&E argues that the Commission should have used hindsight to take a second look at the parties' 1983 estimates of future avoided costs, adjusted the obligations incurred by PG&E in 1983 to reflect the data available in 1986, and adjusted the prices to be paid for the next ten to thirty years pursuant to SO4 based on that 1986 data. This position is contrary to the policies and requirements of PURPA, and has been flatly rejected by the courts.

Pursuant to PURPA, FERC promulgated Regulation 292.304, which sets the rates that a state may require a utility to pay a QF for energy purchased pursuant to PURPA. 18 C.F.R. § 292.304. Subsection (d)(2) of that Section provides that each qualifying facility shall have the option:

> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case, the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) *The avoided costs calculated at the time the obligation is incurred.*

18 C.F.R. § 292.304(d)(2) (emphasis added). Thus, FERC regulations specifically authorize the PUC to approve prices based on estimates of future avoided costs "calculated at the time the obligation [of PG&E] is incurred." That is precisely what was done when SO4 was approved in 1983; *the parties agreed on and the PUC approved the prices to be paid as avoided*

costs regardless of subsequent market price fluctuations. The 1986 PUC decisions merely enforced the parties' 1983 agreement, and thus properly did not subsequently revise their agreement to take 1986 price forecasts into account.

The approach followed by the PUC was approved by the Idaho Supreme Court in *Afton Energy, Inc. v. Idaho Power Co.*, 107 Idaho 781, 693 P.2d 427 (1984). Afton Energy, a cogenerator of electricity in Idaho, petitioned the Idaho Public Utilities Commission ("IPUC") for an order requiring a utility, Idaho Power Company, to enter into a long term, fixed price contract to purchase energy from Afton. Although Afton and Idaho Power had been able to agree on most of the proposed contract terms, there remained a dispute over a provision requiring the IPUC to periodically monitor the prices in the agreement and to adjust those prices if avoided costs increased or decreased. The IPUC ruled that it would order the parties to execute the contract, but that it would not maintain jurisdiction to adjust the prices initially set by the contract.

The Idaho Supreme Court affirmed the IPUC's decision. The court held that Idaho Power's contention that the IPUC was required to monitor the prices in the agreement to ensure that those prices were just and reasonable in the future was inconsistent with the policy, intent, language, and FERC implementation of PURPA. The court pointed to the public comments made by FERC at the time its regulations were adopted which stated that avoided costs calculated at the time an obligation is incurred should be maintained for the duration of the contract. Section 292.304(b)(5) of the FERC Regulations provides that,

in the case of contracts to deliver energy at a future date, "the rates for such purchases do not violate the subpart if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. § 292.304(b)(5). According to the court: "The import of this Section [292.304(b)(5)] is to insure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefit of its commitment as a result of changed circumstances . . . . This subparagraph will thus insure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility." *Afton Energy, Inc. v. Idaho Power Co., supra,* 693 P.2d at 434, *quoting* Preamble to FERC's Regulations, 45 Fed. Reg. 12,214, 12,224 (1980). "Thus we reject Idaho Power's argument that the [IPUC] does not have any authority to establish an avoided costs rate which is fixed for the duration of the contract and which is not subject to the [IPUC's] continuing jurisdiction. It is clear that both Congress and FERC, through its implementing regulations, intended that [QFs] should not be subjected to pervasive utility-type regulation which would result if the contract language proposed by Idaho Power were approved by the [IPUC]." *Afton Energy, Inc. v. Idaho Power Co., supra,* 693 P.2d at 434.

PG&E's argument that PURPA required the PUC to examine 1986 price forecasts when it ordered the price tables contained in SO4 extended is directly contrary to these PURPA sections, FERC regulations, and case authority. When SO4 was approved in 1983, PG&E incurred the obligation to honor the prices established at that time regardless of fluctuations in actual avoided costs, an approach expressly authorized

by PURPA. When it was discovered that some "blanks" had been left in the contract, the Commission correctly interpreted the parties' intent to rely on the pricing methodologies agreed to during the 1983 negotiations and extended the price tables accordingly. The entire pricing mechanism for SO4 was established by the parties and the PUC in 1983 and before, and thus the data and information available at the time the parties mutually agreed to a pricing formula must govern the interpretation of SO4. Again, this resolution by the PUC of a factual dispute surrounding the intent of the parties is not one calling for the exercise of this Court's review. No substantial federal question is raised.

Moreover, PG&E's assertion that its current estimates of future avoided costs are more accurate than the estimates found in SO4 is unfounded. When the parties negotiated SO4 in 1983, everyone realized that there was uncertainty associated with predicting the avoided costs that would be incurred by the utilities over the next 30 years. However, the parties were able to reach an acceptable compromise as to those estimates based on the pricing mechanisms already adopted and approved in SO2. There is no reason to believe that those estimates will end up being any less accurate than PG&E's current estimates 30 years down the road. As the PUC stated, evaluating PG&E's data "requires a crystal ball. The fact is, neither we, nor PG&E, nor the QFs know whether the escalation factors in Table E-2 will prove higher or lower than the change in costs of a combustion turbine, or than inflation generally." Decision 86-10-038 (Pet. App., p. A-135). There is therefore no reason to favor PG&E's 1986 estimates over the prices

added to the tables pursuant to the formulae in place and data available in 1983.

Finally, PG&E's argument would frustrate PURPA's policy of promoting alternative energy sources. *The decrease in PG&E's 1986 avoided cost estimates, on which PG&E relies so heavily, resulted in large part from the increased availability of energy created by the response of QFs to SO4.* Decision 85-04-075 (Pet. App., pp. A-94-95, 99). Inherent in the calculation of avoided capacity costs is the total amount of capacity necessary to ensure that no energy shortage occurs. Thus, as the predicted amount of available capacity approaches the total amount needed, per unit avoided costs decrease. *Therefore, it is precisely because many QFs executed SO4 that avoided cost estimates decreased from 1983 to 1986.* (Pet. App., p. A-99.)

PG&E cannot honestly claim that it is now entitled to walk away from the deal that it negotiated in 1983 because that deal was successful and was executed by many QFs in the ensuing 19 months. If PG&E's argument is accepted, then the response to any successful program to promote alternative energy could be used to abrogate the fixed price provisions of that program, *thereby frustrating the intent of the parties and the goals of PURPA.* PG&E simply cannot rely on changed circumstances in an attempt to argue that the Commission erred in ordering that prices consistent with the 1983 contracts be added to the price tables.

III. The Commission May Set Prices Different from Avoided Costs.

In its brief to the California Supreme Court, PG&E seemed to argue that PURPA and the FERC regu-

lations implementing PURPA constitutionally preempt the Commission's statutory authority to set prices exceeding avoided costs. Although not entirely clear, PG&E now seems to concede that PURPA, based on the New York Court of Appeals' decision in *Consolidated Edison Co. of New York, Inc. v. Public Service Commission*, 63 N.Y.2d 424, 472 N.E.2d 981, 483 N.Y.S.2d 153 (1984), as affirmed by this Court, 470 U.S. 1075 (1985) (appeal dismissed for want of a substantial federal question), allows the states to authorize payments to QFs exceeding avoided costs. However, PG&E now argues that Section 2821 of the California Public Utilities Code does not go as far as the New York statute did, and therefore the Commission erred because it set prices in excess of avoided costs. There is simply no merit to PG&E's argument because the plain language of Section 2821 clearly authorizes the Commission to set any price, including prices in excess of avoided costs, and that such prices shall be deemed "reasonable and prudent for all purposes." Cal. Pub. Util. Code § 2821 (West Supp. 1987). More importantly, however, the reach of the California statute is a matter of state law upon which this Court should not pass.

A. PURPA Permits States to Set Prices in Excess of Avoided Costs.

In *FERC v. Mississippi*, 456 U.S. 742 (1982), this Court addressed the constitutionality of PURPA and the FERC regulations promulgated thereunder, challenged on interstate commerce and Tenth Amendment grounds. This Court held that PURPA was enacted pursuant to congressional authority under the Commerce Clause, 456 U.S. at 753, and that "Congress was not irrational in concluding that limited federal

regulation of retail sales of electricity and natural gas, and of relationships between cogenerators and electric utilities, was essential to protect interstate commerce." 456 U.S. at 758. With regard to the challenge based on the Tenth Amendment, this Court held that Congress could have preempted the entire field of utilities regulation, but that it chose not to do so and instead had imposed on the states the burden of enforcing federal policies in addition to their normal function of regulating state utilities. 456 U.S. at 760-61. Since Congress did not expressly or impliedly preempt the entire field of utilities regulation, only if the PUC's orders directly conflict with or prevent enforcement of PURPA would those orders give way under constitutional principles. The Commission's 1986 decisions interpreting SO4, however, do not conflict with federal law because PURPA and the FERC regulations permit states to encourage the development of cogeneration and small power production facilities to an even greater extent than federal law.

In *Consolidated Edison Co. of New York, Inc. v. Public Service Commission*, 63 N.Y.2d 424, 472 N.E.2d 981, 483 N.Y.S.2d 153 (1984), *appeal dismissed*, 470 U.S. 1075 (1985), the New York Court of Appeals specifically addressed the issue whether a New York state law which set a price in excess of avoided costs for energy produced by QFs violates PURPA. In answering that question, the court held that PURPA and the FERC regulations permit, and even encourage, complementary state regulation of contracts between QFs and utilities, and upheld the New York statute.

The New York court first examined the language of PURPA and concluded that the rules promulgated

by FERC were limited to enforcing the *federal* statute. 472 N.E.2d at 985. When it issued its regulations, FERC explained that complementary state regulation "was not supplanted by PURPA but could be used to *expand* the Federal PURPA-based incentive." 472 N.E.2d at 985 (footnote omitted; emphasis added). "While the rules prescribed under Section 210 of PURPA are subject to the statutory parameters, *the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these* [*alternative energy*] *technologies* . . . . In such a case, however, the higher rates would thus be based on State authority to establish such rates, and not on the [FERC] rules." 472 N.E.2d at 985-86, *quoting* Preamble to FERC Regulations, 45 Fed. Reg. 12,214, 12,221-22 (1980) (emphasis added).

Moreover, the New York Court of Appeals recognized that complementary state regulation setting prices in excess of avoided costs would actually promote the policies embodied in PURPA. The primary goal underlying the enactment of PURPA was to encourage the development of alternative energy projects such as cogenerators and small power production facilities. *See FERC v. Mississippi, supra*, 456 U.S. at 750. A state which promotes these alternative sources of energy by permitting its regulatory agency to set prices in excess of avoided costs is simply promoting the same policy with more vigor, and consequently does not violate the federal law. *Consolidated Edison Co. v. Public Service Commission, supra*, 472 N.E.2d at 986. "The State statute [setting prices in excess of full avoided costs] does not hinder the Federal objective; it furthers it, by enhancing the bar-

gaining position of the alternate energy developer through a predictable, guaranteed rate of $.06 per kilowatt hour . . . . The stability provided by the Public Service Law to the alternate energy producers reduces the perceived risk of a project, encourages investment, and facilitates financing." 472 N.E.2d at 986.

In 1985 this Court dismissed an appeal of *Consolidated Edison Co. v. Public Service Commission*, *supra*, for want of a substantial federal question. *Consolidated Edison Co. v. Public Service Commission of New York*, 470 U.S. 1075 (1985). Such a dismissal is deemed a determination on the merits of the preemption question. *See Hicks v. Miranda*, 422 U.S. 332, 343-45 (1975); C. Wright, Law of Federal Courts 757-58 (4th ed. 1983) ("Summary disposition of an appeal, however, either by affirmance or by dismissal for want of a substantial federal question, is a disposition on the merits"); R. Stern, E. Gressman & S. Shapiro, *supra*, § 4.28.[5]

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[5] The Kansas Supreme Court's preemption decision in *Kansas City Power & Light Co. v. State Corp. Commission*, 234 Kan. 1057, 676 P.2d 764 (1984), was clearly rejected by this Court, and is seriously flawed because the Kansas court failed to consider the legislative history of PURPA and FERC's statements in adopting regulations to implement PURPA. Instead, the Kansas Supreme Court relied on dicta in *American Paper Institute v. American Power and Light Co.*, 461 U.S. 375 (1983), a case involving a constitutional challenge to FERC's regulations, not complementary state law. *Kansas City Power & Light v. State Corp. Comm'n*, *supra*, 676 P.2d at 766 (*quoting American Paper Institute*, *supra*). Finally, the Kansas Supreme Court failed to consider that state law establishing prices for purchase of QF power would further *promote*, not hamper, the goals of PURPA. Given its defects, and this Court's dismissal of the appeal of

After the New York Court of Appeals rendered its decision in *Consolidated Edison Co. v. Public Service Commission, supra,* FERC issued a decision reaffirming the statements in the Preamble to its rules relied upon by the New York Court of Appeals. In *Middle South Services, Inc.*, 33 FERC (CCH) ¶ 61,408 (Dec. 23, 1985), FERC held that a state determination of full avoided costs which involves methodologies different from those used by FERC does not create a conflict between state and federal law, and that FERC should defer to the state determination because Congress gave implementation responsibilities to the individual states. *Id.*, 33 FERC at 61,788-89. Moreover, FERC held that a state, pursuant to its own laws, may set rates *in excess* of avoided costs to further promote alternative energy production within that state. *Id.*, 33 FERC at 61,789. *Thus, it is absolutely clear that PURPA allows states the authority to set prices above avoided costs; PURPA sets only a floor for rates, not a ceiling.*[6]

Consolidated Edison, the Kansas court's decision is not persuasive on any point and hardly represents a "conflict" with the decision in *Consolidated Edison.*

[6] This is further established by *Greensboro Lumber Co. v. Georgia Power Co.*, 643 F. Supp. 1345 (N.D. Ga. 1986), which, based on language in PURPA, FERC's regulations thereunder, the Supreme Court's decision in *FERC v. Mississippi, supra*, and the New York Court of Appeals' decision in *Consolidated Edison Co. v. Public Service Comm., supra*, holds that PURPA was not intended to preempt complementary state law promoting alternative energy production. *Id.*, 643 F. Supp. at 1384; *see also* Lock, *Statewide Purchase Rates Under Section 210 of PURPA*, 3 Solar Law Rep. 419, 446-50 (1981).

B. PG&E's Petition Improperly Seeks an Interpretation of State Law by this Court.

At its end, PG&E's petition appears to admit that PURPA permits a state statute to authorize prices in excess of avoided costs. However, PG&E then asks this Court to examine the relevant California statutory provision, California Public Utilities Code Section 2821, to determine if it, like the New York statute at issue in *Consolidated Edison*, permits the PUC to set prices in excess of avoided costs.[7] PG&E fails to recognize that this Court has repeatedly held that it will not review a state determination of state law. "The Supreme Court has consistently developed its powers with respect to state law from the assumption that generally jurisdiction to review federal question cases does not extend to resolution of state law questions that are also presented." 16 C. Wright, A. Miller, E. Cooper & E. Gressman, Federal Practice

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[7] These Respondents completely disagree with PG&E's interpretation of Section 2821 of the California Public Utilities Code. PG&E's statutory construction argument focuses on the first paragraph of that Section enacted in 1980. PG&E totally ignores the second paragraph adopted in 1983, 1983 Cal. Stats., ch. 868, § 3 (West 1983), and its legislative history. This second paragraph focuses on "prices" and gives the PUC the power to determine "prices" as "reasonable and prudent for all purposes." Cal. Pub. Util. Code § 2821 (West Supp. 1987). The language in question was introduced as an amendment to Assembly Bill No. 1942 by the State Senate on July 8, 1983. (App., p. A-333.) The analysis of Assembly Bill No. 1942 prepared by the State Senate Committee on Energy and Public Utilities clearly shows that the amendment was included to specifically sanction what the PUC was doing under OIR 2 and to confirm that the prices approved pursuant to that procedure or otherwise would be deemed fair and reasonable for all purposes. (App., pp. A-334-36.)

and Procedure: Civil § 4019 at 661 (1977); *see also Murdock v. City of Memphis*, 87 U.S. 590, 626-33 (1875). Thus, although this Court has jurisdiction to examine the precise scope of the federal statute involved and the room left for legislation by the state, this Court generally leaves to the state the question of whether its statute falls within the area permitted by the federal law. *See* 16 C. Wright, A. Miller, E. Cooper & E. Gressman, *supra*, § 4021; *see also Arkansas Electric Cooperative v. Arkansas Public Service Commission*, 461 U.S. 375, 396 (1983) (holding that state was free to regulate wholesale rates for energy charged by a rural electric company).

This Court's disinclination to review a state's construction of its own statutes seems especially well founded in this case because California law (apparently unlike that of other states) specifically empowers the PUC to make findings of fact and issue administrative decisions, just as it did here, subject only to a very narrow scope of review by the California Supreme Court. Cal. Pub. Util. Code § 1757 (West 1975); *City and County of San Francisco v. Public Utilities Commission*, 39 Cal. 3d 523, 530, 703 P.2d 381, 217 Cal. Rptr. 43 (1985). The California Supreme Court refused under California law to "second guess" the PUC's decisions; this Court should do likewise.

CONCLUSION

In summary, the Commission's interpretation of federal law, as clearly set forth in the FERC regulations and in this Court's decisions, does not raise a substantial federal question. Furthermore, when one examines PG&E's request in the latter portions of its

petition, it becomes even more clear that state law issues of fact and contract law predominate over the specious federal statutory question that PG&E attempts to raise. For these and all the reasons stated above, PG&E's Petition for Writ of Certiorari should be denied.

DATED: August 27, 1987

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No. 87-178

IN THE

Supreme Court of the United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California corporation,
Petitioner,

vs.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,
Respondent.

APPENDIX TO BRIEF OF RESPONDENTS ULTRAPOWER, INC., AND GWF POWER SYSTEMS COMPANY IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

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Decision *82 01 103* January 21, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.

OIR 2
(Filed September 3, 1980)

(See Appendix A for appearances.)

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OPINION

Summary

This decision orders the major California electric utilities to file standard offers for power purchases based on avoided cost principles. These offers shall be available to all cogeneration and small power facilities that qualify under the Federal Public Utility Regulatory Policies Act of 1978. The decision finds that avoided cost pricing will promote the maximum efficient development of cogeneration and small power resources, diversifying the energy supply in California and reducing the state's oil dependence.

The standard offer gives qualifying facilities (QFs) a series of options to tailor contracts to meet their varied needs.

Within 45 days, the utilities are ordered to file the following standard offer options which will become effective upon a compliance review by the staff. These options are:

- Facilities providing *as-available electricity* (energy delivered without a long-term contract) will receive an as-available energy and an as-available capacity payment in ¢/kWh, varying by time of delivery. The as-available price will be based on a short-run avoided cost methodology, with capacity reflecting an estimate of the utilities' shortage cost (pp. 30-56 [pp. A-30-55]).

- QFs which agree to certain performance standards may receive a *firm capacity* payment, rather than an as-available payment. The firm capacity payment is available in $/kW/year, and may be contracted for and levelized for up to 30 years. The firm capacity payment, like the as-available payment, is based on a shortage cost methodology. Firm capacity contracts will also include payments for energy (pp. 57-64 [pp. A-55-60]).

The decision orders utilities to file within 90 days proposals for three other option which will become available after additional hearings. These options are:

- Energy payments may be fixed in advance for up to five years for QFs which agree to commit to provide energy over the term of the contract. This energy payment may be tied either to an as-available or firm capacity option. Payments will be based on projected variable operating costs of the utilities (p. 51 [p. A-50]).
- A long term contract, based on a utility's long-run resource plan for both energy and capacity shall be available for QFs. This offer will be based on a long-run avoided cost concept (pp. 64-68 [pp. A-60-63]).

The decision also establishes guidelines for the standard offer relating to interconnection costs, refusal to purchases, line losses and other contract terms.

The decision allows utilities to file for review of non-standard contracts with this Commission for two years after the effective date of this decision.

This decision also sets standards for rates for sale of power to QFs. Standby rates currently in effect are found reasonable for all QFs on demand schedules, and will be updated in general rate cases in proportion to increases in per kW capacity costs. They are eliminated for QFs who achieve an 85% on-peak capacity factor. Alternate standby rates are adopted for QFs on time-of-use rates. A time frame for planning periods of scheduled maintenance is adopted and scheduled maintenance rates are set at regular tariff rates. Added demand charges are waived for maintenance fitting utility schedules. Interruptible service offerings are made available for all large QFs.

I. Introduction

California has a longstanding demonstrated interest in promoting cogeneration and small power production, as

shown by various actions by this Commission and by the California Legislature (see, e.g., Public Utilities (PU) Code Sections 2801-2824). Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Small power production facilities use biomass, geothermal energy, waste or renewable resources, including wind, the sun, and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

In Decision (D.) 91109 in Order Instituting Investigation (OII) 26 we recited the following reasons for promoting the development of such alternate resources:

a. Cogeneration uses fuels more efficiently than when industrial processes and electric generation are performed separately.

b. Alternate generating sources diversify the utility's resource plan and minimize dependence on any single source of generation.

c. Generation from biomass, wood waste, and refuse offers independence from foreign fuel sources. The use of domestic fuels is important for reasons of international economics and politics.

d. The development of many small power plants contributes to system reliability. The probability of many small plants failing simultaneously is less than the probability of one large central station plant suffering a forced outage.

e. The lead time required for construction of a small facility is estimated to be several years less than for large central station power plants. Permitting and siting are considerably

simplified due to the small size and location at an existing industrial facility.

f. The utility in many cases will not have to raise the capital to construct the facility, and the facility will not be included in the utility's rate base.

In D.91109, December 19, 1979, we adopted "avoided cost" as the reasonable basis for payment by a utility to purchase power from such facilities.

Meanwhile, cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which are defined as qualifying facilities under Section 201. For such purchases electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210 further requires the Federal Energy Regulatory Commission (FERC) to prescribe rules as FERC determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities.

On February 19, 1980, FERC issued its final rules implementing Section 210. (Docket No. RM79-55, Order No. 69 (45 Fed Reg 12214).) These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere. The criteria and procedure by which cogenerators and small power producers obtain qualifying status are set forth in the FEC

rules issued under Section 201. (Docket No. RM79-54, Order No. 70, March 13, 1980 (45 Fed Reg 17959).)

The implementation of the Section 210 rules is reserved to state regulatory authorities. Within one year of the issuance of the rules, each state regulatory agency is required to commence implementation, by way of:

> ". . . the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under. . .(the rules), or any other action designed to implement. . . (the rules)."

Within one year each state regulatory authority is required to file with FERC a report describing the manner in which it will implement the rules.

By Order Instituting Rulemaking (OIR) 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards governing the prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities, under the FERC rules. The order and the "Preliminary Draft Staff Report on Cogeneration and Small Power Production Pricing Standards" were served simultaneously on respondents and interested parties. The original schedule contemplated written comments addressing the staff report to be filed by September 29, 1980, the final staff report, and a public hearing on November 3, 1980, for "oral comments on issues pertinent to this proceeding." By Administrative Law Judge's (ALJ) Ruling dated September 18, 1980, the time for filing written comments was extended to October 15, 1980, and the public hearing postponed until December 2, 1980. By a second ALJ's Ruling dated November 21, 1980, the public hearing was postponed until February 3, 1981, so that staff would have sufficient opportunity to assimilate the numerous and substantial comments in preparing its final report. The hearing dates set for December remained on calendar and

parties appeared to offer further comments and to argue several pending motions. At the December hearing, staff moved for an interim order addressing the ultimate applicability of this decision to contracts signed during the pendency of this proceeding. Staff's motion was the subject of D.93054 dated May 18, 1981, and D.93393 dated August 4, 1981, which provide sellers an option to amend contracts to conform with the provisions of this decision.

The final staff report was issued on January 20, 1981. Public hearings to receive comments on the final staff report were held February 3, 4, and 5, 1981.

II. Procedural Matters

The designation of this proceeding indicates that this is one of the first matters conducted under our rulemaking procedures adopted June 17, 1980. The unfamiliarity of the procedure has apparently contributed to a concern that factual issues will be decided without the opportunity for evidentiary hearings. Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and Mass Production Systems (MPS) each filed a written motion asking for evidentiary hearings.

Edison argues that a prehearing conference is necessary to identify unresolved issues that in turn are necessarily resolved in an evidentiary hearing. It contends that an inadequate factual basis for this decision denies due process of law to affected parties.

In support of its position, Edison cites FERC rule Section 292.401(a) which provides for implementation of the rules "after notice and an opportunity for public hearing." It asserts that the hearing allowed in this matter is insufficient for FERC purposes. It also states that the staff report does not have an adequate factual basis upon which to establish the proposed standards. It argues that only an evidentiary hearing will allow this Commission to "establish standards which will equitably balance those vary-

ing interests which it is the responsibility of the Commission to protect."

SDG&E also requests a prehearing conference which it contends is required for the following reasons:

1. To expand the scope of the proceeding to permit an evidentiary hearing for the purpose of reviewing standard form contracts.

2. To determine the need for an evidentiary hearing on existing issues.

3. to place limitations on the proceeding.

4. To resolve certain procedural problems.

In its brief SDG&E observes some change in the staff position but argues that staff's proposal still unnecessarily limits subsequent evidentiary hearings.

MPS argues that the commission should provide for evidentiary hearings (within the scope of OII 26) to investigate and adopt standards to ensure system safety and reliability of interconnected operations. It contends such standards are necessary to the development of safe, economical cogeneration and small power production hardware, leading in turn to qualifying facilities that rely on such hardware.

Staff replied initially that it would consider such motions in the nature of comments in preparing its final report. Various other parties support one or more of the motions.

Staff in its final report argues that this procedure satisfies the "public hearing" requirement imposed by FERC. It states that FERC rules specifically authorize state agencies to implement rules by issuing regulations or taking other action reasonably designed to implement the rules. The rulemaking procedure, staff further argues, is an appropriate means for the consideration and adoption of standards and guidelines governing the utilities' purchases

from qualifying facilities. Although staff recommends evidentiary hearings to review the offers which the utilities will make in compliance with such standards and guidelines, staff believes that any evidentiary hearings which might have been instituted before the establishment of these standards and guidelines would have been premature, time-consuming, and ultimately inconclusive.

We agree with staff that the rulemaking procedure is an appropriate way to decide generic policy questions such as the issues we resolve in this decision. We also agree with the substance of the three motions that certain issues will require resolution in an evidentiary proceeding. In the following discussion, we provide for later evidentiary hearings that will address the primary concerns of the moving parties. Because the evidentiary proceeding we provide is not identical to any of the moving parties' proposals, however, we deny each of the motions for procedural purposes.

III. Applicability

This proceeding has been initiated to further implement our decision in D.91109, to respond to FERC rules, to discharge our responsibilities under Public Utilities Code §2821. To avoid confusion, we use the terminology and structure of the FERC rules throughout this decision. A number of parties to this proceeding have raised questions about the applicability of these rules either to certain California utilities, or to particular entities which are interested in contracting with utilities. We address these questions in this section.

The staff raised the issue of the applicability of these standards in cases where utilities have an equity interest in a facility. One criterion describing a qualifying facility is a limit of utility equity ownership to no more than 50%. In its final report staff analyzes applicable statutes and rules relating to utility ownership and offers the following summary:

"The approach suggested by FERC is as follows: Given state regulatory authority over retail sales, the Commission may prohibit the parent utility from passing on to its ratepayers all of the expenses paid to its subsidiary. In return the Commission would allow the utility subsidiary to earn a higher rate of return than the parent. Accordingly, the parent utility would only be entitled to recover through rates its purchases based on cost of service rather than avoided cost. This approach recognizes that ratepayers should derive some benefit from incurring the additional risk created by the utility subsidiary in potentially affecting capital ratios of the parent without limiting the amount of expenses recoverable by the parent. There appears to be little incentive for the utility to negotiate prices at other than the parent's avoided cost if its subsidiary could enjoy high profits, subsidized by the ratepayers of the parent."

"The FERC's approach thus equitably balances the risks and benefits faced by the parent and its subsidiary. In the event of project failure, the subsidiary could not recover its costs through amortization. Such costs would be borne by the subsidiary's stockholders. The parent, in turn, would make no avoided cost payment to the subsidiary, having received no power. In the case of project success, however, the unregulated subsidiary could retain all profits and earn a greater rate of return than its parent. . .

"Review of purchased power costs incurred by the parent utility from its subsidiary should be made in ECAC proceedings. Capital expenses incurred by the utility should be reviewed in general rate proceedings."

The resulting staff recommendation is that the Commission should consider limiting the amount of recovery of purchased power expenses paid to a QF owned in part by a utility.

Pacific Gas and Electric Company (PG&E) urges that this Commission reject staff's recommendation. It argues:

> "When utilities invest in QFs the utilities' shareholders bear risks greater than those assumed in traditional utility investments. As a reward for taking the risk that expenses may not be recovered in the event of project failure, the utilities should have the opportunity to retain the full benefits of the venture, the same as any other investor in a QF. It has been determined by both the FERC and the Commission that to adequately encourage and reward investors in QF projects, the investor should be allowed to receive full avoided costs.
>
> "If the Commission wants to strongly encourage development of cogeneration and small power production facilities, it should allow utilities to participate in this energy market with incentives equal to those granted to others. The effect on the ratepayer is the same whether the power is purchased from a QF owned in part by a utility, purchased from a QF in which a utility has no equity interest, or generated from conventional resources. At the same time, a greater number of preferred resources will be developed."

PG&E concludes that such incentives will encourage utility investment in QFs, financially strengthen the utility, and improve its ability to build preferred resources, ultimately reducing the cost of serving its customers.

Edison also argues that staff's proposal is unreasonable. It contends that federal authority preempts state inter-

ference in utility - QF relations, and asserts that even without such preemption public policy considerations support the recovery of full avoided costs by the QF from the utility and by the utility from the ratepayer.

SDG&E also argues that "the supremacy clause would preclude reconsideration of whether the rates are just and reasonable for the purpose of rate recovery by the utility." It characterizes staff's position as apparently due to a misinterpretation of certain comments accompanying FERC proposed rules.

We find that staff's recommendation should not be adopted.

PURPA permits utilities to own up to 50% of a cogeneration or small power facility otherwise qualifying under the act with that facility still retaining its qualifying status. Such facilities should therefore be eligible for full avoided costs under the conditions adopted in this proceeding.

While facilities with less than 50% utility ownership are eligible for avoided cost (assuming all other requirements are met), we note that this Commission has continuing responsibility over the rest of utility operations, including financial health, which could be directly affected by a utility's equity involvement in qualifying facilities. The Commission has responsibility in three areas which are germane here.

First, the Commission must consider the potential anticompetitive aspects of utility behavior. In this regard, when a utility is approached by a large number of aspiring QFs, we must assure that its own affiliates do not receive special treatment, e.g., more rapid consideration, less difficulty in resolving interconnection issues, etc. It is important that utilities do not stifle competition in the QF market in this or any other way.

Second, there is a concern that utilities would have an incentive to keep avoided costs high (or choose methodol-

ogies that would produce such results) if their own affiliates could receive such prices. A related concern is that a utility would have an incentive to negotiate nonstandard offers that are above avoided costs if it has an ownership interest in the qualifying facility.

Our last, and perhaps most important concern relates to the fact that utility ownership of qualifying facilities would be a step toward utility diversification into unregulated activities. Any such diversification into unregulated ventures may have an impact on the regulated utility business for which this Commission is responsible. Our primary concern is the protection of the financial integrity of the regulated entity (i.e., new unregulated ventures should not impair the utility's ability to raise capital, its bond rating, etc.) and the avoidance of any subsidization by the regulated entity (and thus its ratepayers) of the unregulated business.

Utilities should be aware that while we are not denying their eligibility to participate as qualifying facilities under PURPA, such involvement will require greater scrutiny of utility operations on our part relating to the concerns addressed above. Any utility may come forward with a proposal for partial ownership of a QF and we will review these matters on a case-by-case basis, with the intent of protecting the interest of both ratepayers and any QFs who might be disadvantaged competitively.

Staff also suggests that avoided cost principles should not apply to facilities in which a utility owns an equity interest greater than 50%. Because such facilities are not "qualifying facilities" this issue is not ripe for resolution in this proceeding. Therefore, we make no judgment in this regard. Similarly, staff introduced the issue whether avoided cost principles should apply to facilities that are not "qualifying" for reasons other than ownership. The resolution of this issue is beyond the scope of this proceeding.

Advisory Services Corporation (ACS) raises the question of the extent of state regulatory jurisdiction over joint ownership arrangements where the utility owns the energy resource and the nonutility owns the facility. Staff argues that FERC does not intend that such an arrangement attain qualifying status. It states that "the underlying assumption is that the nonutility participant owns the resource which, without utility assistance in financing, would remain undeveloped." Staff contends that "the very basis for avoided cost payments does not apply to utilities developing their *own* resources," (emphasis in original) and concludes "the utility can clearly generate the energy and capacity itself, and does not require avoided cost payments."

While we are not persuaded to adopt staff's conclusion, ACS and the staff do raise an important question. Utility owned resources generally are purchased under the assumption that they will be employed on a regulated, cost-of-service basis. It is conceivable that a resource currently owned by a utility (and presumably acquired to be developed on a regulated, cost-of-service basis) could be more fully developed as a resource used in a qualifying facility. However, any profit involved in the transfer of such a resource from the utility as a regulated entity to a qualifying facility is certainly of interest, and will be considered in general rate proceedings.

The Bureau of Electricity of the City of Alameda (Alameda) cites a filing by this Commission before FERC in Docket No. RM-81-2 regarding geothermal development in which we asked that avoided cost principles not be applied to geothermal fields undergoing rapid commercial development. Alameda recommends that the Commission:

> ". . . extend to other forms of small power, biomass, or cogeneration facilities the same rationale that prompted it to seek from the FERC authority to exempt from avoided cost pricing

> standards geothermal facilities which are shown to be commercially feasible without such economic assistance. As the Commission noted in its FERC comments, avoided cost pricing does have the effect of excluding municipalities and other nonprofit entities from competing to develop geothermal sites because their avoided costs are lower than other entities, such as PG&E. Municipalities such as Alameda could be excluded from competing to develop other types of small power production or biomass generation facilities for the same reason. If in fact facilities can be developed at less than 'full avoided cost,' but are not due to the Commission's regulations, the developer reaps a windfall at the consumer's expense. This is not consistent with the public interest."

Consequently, Alameda proposes that we "retain, or if necessary seek to obtain" authority to exempt from avoided cost principles any QF where the seller is "ready, willing and able to develop on the basis of less than fully avoided costs."

We decline to adopt Alameda's recommendation, which we construe as an invitation to return to the "share the benefits" doctrine that we repudiated in D.91109. We believe that payment of avoided costs provides a basis for most fully exploiting all economical cogeneration and renewable energy resources. Although couched in the guise of promoting competition, Alameda's proposal is actually anticompetitive by limiting the selling price. However, nothing in this decision precludes a seller who is "ready, willing and able to develop on the basis of less than fully avoided costs" from agreeing to do so.

Another problem regarding the applicability of avoided cost principles is raised by Sierra Pacific Power Company (Sierra). It cites certain factors that it contends "make

Sierra Pacific unique when compared to the large California utilities used in the evaluation and analysis of Co-Generation and Small Power Production Pricing Standards," including the following:

1. In view of its relative size, a single large QF would represent a disproportionate share of its total resources.

2. Because of its location and the configuration of transmission systems its flexibility to import or export power is limited.

3. The addition of a large QF could result in substantial excess capacity.

4. Its cheapest power is purchased from Utah Power & Light Company. During particular times of the year purchases of QF power would require curtailment of Utah power.

Based on these and other reasons, Sierra recommends that "the final regulations should contain some recognition of both the size of the utility and the size of the facility."

We find that Sierra's points are well made and that its unique status is appropriately recognized. However, rather than simply seeking to excuse Sierra from applying avoided cost principles, we conclude that these concerns are best reflected in the development of Sierra's avoided costs. This approach is discussed further in that portion of this decision regarding purchase terms and conditions.

San Bernardino Valley Municipal Water District (SBVMWD) has introduced the question whether avoided cost principles should apply to diversions of water from a utility-owned hydroelectric facility. The issue is illustrated by the current negotiations between SBVMWD and Edison.

Edison contends that water diversion plans are beyond the scope of this proceeding. Water diversion is alleged

to be a matter of water law, not related to the issue of simultaneous purchase and sale between a utility and a QF. We note that this problem has also been raised in Edison's annual Energy Cost Adjustment Clause (ECAC) reasonableness review, Application (A.) 60321.

We agree that the proposed water diversion is beyond the scope of this proceeding as it does not involve a sale of electricity by a facility qualifying under FERC rules. In D.92496 we instructed Edison and SBVMWD to negotiate an agreement 60 days from the date of that decision. An extension of time was subsequently granted. We will be reviewing any agreement submitted and will take appropriate action in the next Edison ECAC filing.

IV. Purchase Terms and Conditions

A. Introduction

Under Section 210 of PURPA and the corresponding FERC regulations, each regulated utility is required to file projections of its incremental energy and capacity costs and its capacity construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs. The first filings of these data were required by November 1, 1980. The rates determined by the Commission will be appropriate for the type of service involved and will reflect the costs avoided by the utility as a result of purchasing generation from the QF.

In determining avoided costs, the FERC regulations require that the following factors be taken into account to the extent practicable:

1. The data filed with the Commission concerning incremental generation costs;

2. The availability of capacity or energy from a QF during the system daily and peak periods, including:

i. The ability of the utility to dispatch the QF;

ii. The expected or demonstrated reliability of the QF;

iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for noncompliance;

iv. The extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utility's facilities;

v. The usefulness of energy and capacity supplied from a QF during system emergencies, including its ability to separate its load from its generation;

vi. The individual and aggregate value of energy and capacity from QFs on the electric utility's system; and

vii. The smaller capacity increments and the shorter lead times available with additions of capacity from QFs;

3. The relationship of the availability of energy or capacity from the QF as derived in subparagraph 2, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF, if the purchasing electric utility generated an equivalent amount of electricity itself or pur-

chased an equivalent amount of electric energy or capacity.

Under FERC rules no electric utility is required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of power itself.

In this part of this decision we consider whether to adopt more substantial data filing requirements as proposed by staff and the extent to which the particular factors identified by FERC should be taken into account in developing standard price offers for each utility.

B. Data Requirements

Section 292.302 of the FERC regulations requires that the following data be filed:

"(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current year and each of the next 5 years;

"(2) The electric utility's plan for the addition of capacity by amount and type, for purchases

of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

"(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases."

A special rule is provided for small utilities. State regulatory authorities are allowed to impose different data requirements after notice and opportunity for public comment.

Staff proposes that this Commission require that the following data be filed:

a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel(s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW,

dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

e. The estimated operation and maintenance, administrative and general, and all other fixed and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental

fuel increases, incremental heat rates and such, will be stated.

i. Results will be presented in summary table(s) for final total avoided costs (e.g., paragraphs a, c, d, e, f) after all effects are taken into account (e.g., losses).

The data filing is proposed to be made within 45 days of this decision and every two years, beginning June 30, 1982.

Specific reasons are offered by staff for the more thorough data filing requirements proposed. These are summarized as follows:

Avoided Energy Costs - FERC requires a five-year forecast. Staff argues that QFs are reasonably provided an estimate of marginal energy costs over the life of a contract. Forecasts of marginal costs for at least 10 years are necessary to assist QFs in determining an estimate of potential cash flows. Forecasts should be reported in terms of constant and escalated dollars.

Resource Plan The Commission should use the same costing horizon for this purpose as for others. The proposal is alleged to be "sufficient and consistent" for this purpose.

Transmission and Distribution - Whether transmission and distribution facilities are avoided by purchases from QFs is a factual question. Staff argues that avoided cost data should be filed and the matter examined, as there may be individual cases in which payment is justified.

Operation and Maintenance, Administrative and General - Such costs are either fixed or variable. When a QF provides capacity, the avoided cost should include the avoided fixed costs. When a QF provides energy, the avoided cost should include the avoided variable costs.

> *Loss Factors* - Section 292.304(3) specifically provides that avoided costs may reflect costs or savings from variations in line losses to the extent practicable. Payments to a QF serving its own load should reflect the losses avoided by the utility from not having to generate the electricity itself.
>
> *Levelized Annual Cost Rates* - Each utility should be prepared to support its calculation of levelized annual cost rates used to translate dollars per kilowatt into dollars per kilowatt per year.
>
> *Escalation Factors* - Whether costs are expressed in real or nominal terms, the utility's assumptions regarding escalation should be filed to allow parties to use their own assumptions.

The utility response is varied.

PG&E proposes to include nearly all of the staff's provisions, omitting only the reference to loss factors. SDG&E similarly proposes to include nearly all of staff's provisions, omitting only the reference to transmission and distribution plant. Edison argues that to require further data in addition to that required by FERC would be excessive, burdensome, and would not be cost-effective.

The data required must be sufficient to develop a standard offer consistent with the adopted guidelines and for qualifying facilities to reasonably forecast the direction of avoided cost over time. The staff data requirements appear to be reasonable and will be adopted. However, many data items sought by staff are included in other documents of the utilities which are required to be filed with this Commission or with the CEC. To require all of this data to be filed every two years may result in both duplicative work and inconsistent data. Therefore we do not adopt staff's proposed filing schedule. Instead, we shall require staff to submit a revised plan for the filing of data for

our consideration in further hearings. Staff shall consult with the utilities and the CEC regarding other filing requirements which currently exist. Staff's revised plan should seek to minimize duplicative filings and make available at all times the most current information available.

While we have asked staff to develop an ongoing plan for data filings, it is important that initial data filings be filed promptly. Therefore we shall require all of the above information to be filed within 45 days. These filings may incorporate data from other filings as appropriate to avoid duplication. We will consider modifying these data requirements after further proceedings on specific price offers or as needed.

The staff report addresses the questions of which utilities should be required to file data. "Sierra has not filed data under Section 292.302, but has filed marginal cost data under Section 133 of PURPA. CP National believes they should not be required to provide cost data." CP National buys its electrical requirements from PG&E and Nevada Power Company.

Staff recommends that Sierra file the specified data, but that CP National file only the rates it pays for purchases, together with the avoided cost data of its supplying utilities. CP National should be able to file by referring to the avoided cost data of its supplying utilities. We adopt the staff's recommendation.

C. The Standard Offer

1. Introduction

We have previously referred to the "standard offer". This is the expression widely used by the parties to describe the terms and conditions associated with the utility's obligation to purchase from a QF at the utility's avoided cost. The standard offer is available to all QFs, and represents a complete transaction, including prices, interconnection requirements, and other relevant factors. A central

aspect of all such offers will be the standard rates for purchase.

Section 292.304, paragraph (c), provides, in part:

> "(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
>
> "(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts."

Standard rates for purchases may differentiate between QFs using various technologies on the basis of their differing supply characteristics and must be consistent with the factors listed in Part IV, A, above. As discussed below, in this decision we provide for standard rates for QFs of 100 kW or less and for more than 100 kW. The rate has relevance only in relation to the mutual obligations of the parties. In this decision we consider the nature and extent of such obligations. The result is the standard offer.

The standard offer has particular significance in terms of the existing and anticipated ratemaking treatment to be afforded utility purchases of energy and capacity provided by QFs. Purchases under the standard offer are *per se* reasonable and a utility's expenses for such purchases are recoverable in the same fashion as other purchased power expenses (in ECAC proceedings, for the larger utilities) without further review. Purchases at rates, terms, or conditions other than the standard offer are recoverable through ECAC or other appropriate procedures subject to a showing of reasonableness. Because of the different degrees of risk for the utility, there is widespread interest in whether the Commission will review nonstandard contracts prior to their becoming effective.

In adopting the parameters for rates that will be part of the standard offer, we are establishing a definition for a utility's avoided costs to be applied when purchasing energy from qualifying facilities under the terms and conditions of a specified standard contract. To facilitate discussion of the specific issues related to avoided costs as raised in this proceeding, we will first make some general observations.

The Commission has found in recent years that avoided cost (or marginal cost) pricing has significant benefits when applied to ratemaking. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity. When marginal costs are used as the basis of rate design, consumers receive an efficient price signal. When adopted for purchasing electricity from third parties, the price encourages full economic development of those resources. Avoided cost pricing parallels the prices that would be established in a competitive market, providing many of the incentives for efficient resource allocation that a competitive market provides.

Some argue that ratepayers are disadvantaged when avoided costs are paid to qualifying facilities, because in some cases these facilities can produce electricity at less than the avoided cost price. While it may be true that some QFs could be brought on line at a purchase price below avoided cost, such a price would not be sufficient to bring in other QFs capable of producing power at prices up to the avoided cost price. The point of permitting avoided cost pricing is to encourage the fullest possible efficient development of QF resources that can effectively and economically compete with utility resources. By opening this market, the supply of electricity is increased, which should lower customers rates over time. Heavy utility reliance on oil and gas fuels to generate electricity has caused rates in California to skyrocket. Avoided cost pricing is intended to stimulate development of substantial generating capacity that will reduce utility oil and gas con-

sumption. In addition, system reliability is increased by the presence of larger numbers of smaller facilities.

If anything, this Commission believes that the avoided cost signal to QFs is a conservative one, as it does not include the tangible but hard to quantify "social costs" that are associated with new utility supplies and which are avoided through the purchase of QF power. These "social costs" include the risks associated with imported energy supplies and environmental degradation related to conventional generation. While several parties suggested that we explicitly include "social costs" in the avoided cost calculation, we are not including such factors at this time.

We prefer to recognize social costs in the general policy judgment that QF production is competitive at avoided costs. This conclusion is reflected in the terms adopted in this decision that are intended to promote QF development.

We concur with FERC rules which require full avoided cost pricing of power from qualifying facilities. The issue we face now is how to arrive at avoided cost, not whether it should be paid. This proceeding has demonstrated that defining and calculating avoided cost is far from a trivial exercise, involving conceptual, empirical, and technical issues. Some of the issues cannot be resolved without further hearings. However, we resolve most of the major conceptual questions in this decision, and this will simplify the hearings that follow.

Before discussing each of the standard offers in detail, we will discuss the relationship between the offers and the method for using avoided cost principles to derive each of the offers ordered herein.

The first type of offer described below is a standard offer for "as-available" QF power, the price which the FERC indicates should be based upon the "purchasing utilities' avoided costs calculated at the time of delivery."

The value of a unit of QF power delivered at any given point in time is equivalent to the cost that the utility would have to incur to produce an equivalent amount of power at that time. This is the short run marginal cost of electricity production in the utility system. As this Commission discussed at length in a recent PG&E rate case, (D.93887, December 30, 1981), the short run marginal cost of utility electricity production is the highest variable operating cost per unit of electricity produced at a given time plus a shortage cost which reflects the effects of the added increment of production on reserve margins and reliability. As these costs are avoided through purchases of QF power, the purchase price paid to QFs under the first offer is tied to the short-run marginal cost. This will include an "energy payment" equivalent to the utility's marginal operating cost and a "capacity payment" equivalent to the utility's marginal shortage cost. The purchase price, following the avoided short run marginal cost, varies by time of day and time of year.

The FERC rules also call for offers that are made "pursuant to a legally enforceable obligation . . . over a specified term . . . (with) the avoided costs calculated at the time the obligation is incurred." This type of offer thus takes the form of a long-term standard offer which must be based on projections of avoided costs. Such long term offers give greater certainty to both the QF and to the utility and its ratepayers. Following the same economic principles described above, we order long-term standard offers which are based on projections of the utility's short-run marginal costs. Such offers reflect the expected short-run marginal cost that the utility will avoid through purchases from QFs at each point in time over several time periods. The price includes an energy component which is tied to short run marginal operating costs in each period and a capacity component which is tied to short run marginal shortage costs in each time period. Energy payments

are allowed for up to five years, firm capacity payments for up to thirty years. A levelized payment option is ordered for capacity payments.

A final long-term avoided cost offer described below is based on projected long-run marginal costs rather than short-run marginal costs. These offers should be roughly equivalent over time, since the utility's short run marginal cost can be expected over time to fluctuate around the utility's long-run marginal cost. The latter is defined as the capital and operating costs of marginal additions to the utility's generation capacity. The avoided cost price offer that is based on the long-run marginal cost will be a more stable pricing alternative and will place system capacity additions derived from QF investments on an equal footing with those derived from utility investments. This long-term resource plan-based price offer for firm energy and capacity will be for periods up to thirty years, with energy and capacity payments tied to the utility's long-run marginal energy and capacity costs.

We note in passing that while long-run standard offers can be based on either projected short-run marginal costs or projected long-run marginal costs, there is debate on the development of the long-run marginal cost. We will reserve or further review the proper relationship of energy and capacity in the long-run standard offer.

We are ordering utilities to file an array of offers based on different terms and conditions, and to provide reasonable notice of such offers. Just as most markets develop a combination of pricing arrangements ranging from a spot price to long-term contracts, we think it is appropriate that qualifying facilities receive a variety of standardized options to better serve their particular needs. In all cases, standard contracts should be based on avoided cost principles.

2. Standard Rates for More Than 100 Kilowatts

a. In General

The nature of the standard offer to QFs of more than 100 kW is the central issue in this proceeding. The adequacy of its terms will largely determine the extent of QF production. The flexibility of its terms will determine the extent to which parties resort to nonstandard contracts.

The term "standard offer" is itself an oversimplification. This decision directs that each utility offer a choice of contract terms at the seller's option. These choices are intended to be economically equal over the life of a contract. It is such equivalence that qualifies each as a standard offer.

The context for these choices is provided by FERC Regulation Section 292.304(d):

> "Each qualifying facility shall have the option either:
>
> "(1) to provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> "(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> "(i) The avoided costs calculated at the time of delivery; or

"(ii) the avoided costs calculated at the time the obligation is incurred."

Each of these choices is provided for in the "standard offer" as developed below.

b. As Available Contracts

i. Energy

The utility's avoided energy cost at time of delivery in the as-available offer conceptually is based on short-run operating costs. It should reflect the variable cost of providing an additional unit of electricity. The methodology for actually calculating this number may be refined over time, as we become more sophisticated. Also, payments may be differentiated by time of use into more costing periods in the future as technology permits.

The utility's avoided energy cost at the time of delivery for most of the utilities is currently the product of the purchase price of oil used as the marginal fuel over the last three months and the forecasted incremental heat rates (IHRs) of the plants used by the utilities to follow load.

The intent of the energy prices is to capture as accurately and timely as possible the current marginal energy cost incurred by the utility. To accomplish this the IHRs will henceforth be calculated using the current resources of the utility without speculation on the operational date or operational characteristic of major new units. The impact of major new units will be included in the calculation of energy prices only when they have actually become operational, and actual operational experience will be used to assess the impact on marginal energy costs. This is consistent with the calculation of short-run energy cost which we recently adopted in the PG&E and SDG&E general rate decisions.

Staff believes the as-available energy payment by any utility should be uniform to all QFs, treating any adjust-

ments in the aggregate. PG&E disagrees. It argues that differences between QFs should, where possible, be reflected in prices. It states:

> "Although a QF may pay for generation, transmission, distribution, and losses in its customer rate, it does not mean that its full avoided cost price should include all these items. . . .
>
> "Although certain costs are calculated on a systemwide basis for rate-making, it does not logically follow that they should be calculated on a systemwide basis for QF pricing.
>
> "It appears that FERC meant to discriminate among QFs based, to the extent practicable, on the factors outlined in Sector 292.304(e). It is up to the Commission to decide the limits of practicability in reflecting these factors in purchase prices for QF power."

PG&E recommends that transmission and distribution costs not be incorporated in the standard price offers based on full avoided cost. It also proposes to evaluate line loss impacts on a case-by-case basis.

We adopt the notion of a uniform energy price. Transmission and distribution costs should be analyzed in the aggregate and appropriate adjustments made. We conclude that it is not practicable to treat such factors on an individual basis. Costs or savings resulting from variations in line losses should also be aggregated for standard offer purposes except for remote sites. It is unreasonable to reduce the payments to centrally located QFs because of higher line losses that are experienced by a utility in receiving power from a large remote QF. Losses will be examined individually for projects one MW or larger developed at sites remote from load centers where the incremental loss increase resulting from substitution of QF generation at the remote site exceeds 150% of average

transmission systems losses. Losses will be examined individually for such remote facilities.

ii. Capacity

The most controversial issue in this proceeding is the nature of the obligation to be undertaken by a QF in order to qualify for capacity payments. The general utility position is that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs. PG&E does recommend that utilities pay for as-delivered capacity at 35% of the current single-year capacity price, but states that this Commission must recognize that such a payment is intended to "encourage" the development of QFs. "The utilities will not be able to justify these payments as true avoided costs unless and until data not now available are collected and studied."

The intended beneficiaries of PG&E's proposal are not impressed. There is no recognition on their part that a 35% payment would "encourage" their participation. Two alternates have emerged: payments based on 50% or 100% of the capacity value.

Staff offers an analysis that suggests that the threshold question is philosophical whether to treat QFs as an increase in supply, or as a reduction in demand. While various parties complain of the oversimplification that results from such labels, the concepts have proven analytically useful.

If QF production is treated as an increase in supply, objective performance standards are appropriate. "As an increase in supply, the value to the utility depends on whether the utility has control of the power (dispatchability), whether the electricity is reliable, is available for more rather than fewer years, is available during emergencies and so on." This is the approach favored by the utilities.

According to the staff, much more lenient requirements are appropriate if QF production is treated as a reduction in demand:

> ". . . the QF need not be dispatchable by the utility in order to qualify for the full avoided cost rate. The QF need not produce a certain predetermined reliability. The QF need not sign a long-term contract and be subjected to termination penalties and sanctions for noncompliance. The QF need not schedule outages with the utility, or supply power (decrease demand) during emergencies."

This approach is generally supported by prospective QFs and is characterized as consistent with marginal cost-based rates.

Staff does not propose to limit the reduction in demand approach to QF production serving only the QF's own load. It states that treating positive net input to the system as a decrease in demand is appropriate:

> ". . . (1) if one is willing to depend on the QF market and QF equipment to insure supply just as one depends on the customer market and customer equipment to insure demand; (2) if one views QF electricity as a reduction of the number of megawatts the utilities of California must supply (since demand is reduced) rather than as a fixed resource in the resource plans for California utilities; (3) if one believes the effect on the electric system is the same from a QF reducing demand on the utility (freeing utility plant for other use) as from a QF providing a positive net input; (4) if one believes the underlying economic forces will control the relationship without the need for objective performance standards; (5) if one is willing for ratepayers to assume some risk for the development and operation of the QF market

> comparable to the risk ratepayers now assume for utility-owned plants; (6) if it is administratively infeasible to enforce objective standards in some cases (especially very small QFs); (7) if one desires to give QFs the most freedom reasonable to build and operate their facilities according to the economic forces which permeate the relationship; (8) if full avoided cost rates do not allow the utility to control an investment owned by others; and (9) if the lessons of conservation have taught us that a reduction in demand is the same as an increase in supply."

Although the staff report discusses each approach at length, staff takes no position regarding this issue.

SDG&E supports the "increase in supply" approach and contends that this Commission is without discretion to do otherwise. It argues that the FERC regulations require the consideration of the particular factors enumerated in Part IV, A above, and states:

> ". . . it is practicable to apply many of the factors pertaining to capacity to the individual capacity rate. Staff would not apply some of the factors even though it is practicable to do so because of its philosophic debate as to whether QFs should be treated as an increase in supply or a decrease in demand. Since the PUC does not have discretion to refuse to apply a factor once it is determined to be practicable to do so, the debate should be pragmatically resolved in favor of treatment of QFs as an increase in supply."

SDG&E further contends that aggregate capacity is not practicably reflected.

Edison states that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs:

> "It would be imprudent indeed for a utility to defer or refrain from installing capacity resources on the mere hope or even expectation that enough as-available energy will be available when needed to meet the peak load imposed with a prudent reserve margin.
>
> "Prudent utility planning requires that sufficient committed capacity be available when needed to meet the peak load imposed with a prudent reserve margin."
>
> * * *
>
> "Even if a QF is contractually bound to provide capacity resources, the length of that contractual obligation will determine how long a utility is able to defer a capacity installation, and therefore, the actual capacity-related cost which will be avoided."

Edison does support a "pay for performance" concept which Edison states "neither assumes a capacity value nor does it assume no capacity value." It is alleged to pay a QF for its true capacity value regardless of technology.

As stated earlier, PG&E does propose a payment for as-delivered capacity, though it contends that its proposal cannot be justified in terms of true avoided costs. PG&E expressly supports the "increase in supply" approach. It argues:

> "A QF willing to give PG&E more control over its generation by accepting performance standards and contractual obligations has a higher value to the utility. The performance of a QF selling contracted capacity will be measured to evaluate its equivalence to utility generation. In cases of Firm Capacity, it is PG&E's position that objective standards, termination provisions,

> and sanctions are absolutely necessary. Price alone does not provide sufficient incentive to deliver the capacity when it is needed."

PG&E proposes that QFs selling contracted capacity will be paid up to the full cost of a PG&E resource, and that such payment can be made on a levelized basis.

Nonutility parties generally support the "reduction in demand" approach. CEC states that the "demand reduction" model is clearly superior:

> "Treatment of (QFs), at least below 50 megawatts in size, as miniature power plants does not reflect the aggregate benefits to the system which result from their small size. We note that the aggregate experience of a group of (QFs) will be better than the experience of any individual (QF). This is a case where the whole is greater than the sum of the parts. This is particularly important for wind generation, where the dispersion of windmills over a large geographic area may result in more benefits to the system than the sum of individual windmill capacity values or individual windfarm capacity units. The key to correct pricing for performance of small units is recognition of the diversity of outages in small units. Utilities have recognized this diversity for years in developing rates and demand forecasts for customer classes; yet they by and large propose not to use this conventional analysis for small dispersed generators.
>
> ". . . The application of reliability and dispatchability criteria applicable to the supply model by utilities would result in underpayments to (QFs) relative to aggregate performance and even relative to performance of conventional power plants. Our detailed examination of the wind contract for PG&E, for example, indicates that if

> Rancho Seco were a windmill (or any type of (QF) for that matter), it would not receive capacity payments."

CEC supports a time-differentiated capacity payment in cents per kWh, paid for performance.

The Natural Resources Defense Council, Inc. (NRDC) also supports the "demand reduction" approach. It criticizes the "supply increase" method as overlooking:

> ". . . the difference in size of supply provided by a QF and a regular power plant. Where QFs are small their lack of availability will have far less impact on the utility system than would a failure by a major power plant."

It states that performance standards fail to provide recognition of reliability obtained by aggregate performance. "QF reliability will be increased by the use of time-differentiated rates, which will encourage QF generation during periods when it is needed most." Due diligence is cited as the only necessary condition.

MPS supports the "reduction in demand" approach as conceptually accurate:

> "Where the utility has no direct control of the customer's resource (generating equipment), the utility only experiences customer generation as a reduction of load. The utility serves a different demand curve than it otherwise would. Since the demand curve is the direct determinant of the utility's incurred costs, the alteration of this curve is the utility's avoided costs. It should be noted that the only effect experienced by the utility generating stations is the total reduction in system load caused by the instantaneous sum of all customer generation. This is an accidental result, exactly like the accidental result of all customer load, the traditional demand curve."

It argues that since both consumption and generation have exactly the same effect on the utility's load curve, the established method of regulation of sales serves as an excellent model for regulation of utility purchases.

Henwood Associates, Inc. (Henwood) agrees that "as available power will exhibit predictable patterns in a fashion analogous to customer demands."

> ". . . It should be recognized that this is a result which depends upon the number of QFs being present in the market-place and that a transition period will occur between now when few producing QFs are in existence and later when the requisite number of QFs have succeeded with their plans.
>
> "This transition period gives rise to an argument which (may be called) the chicken and egg argument. . . .
>
> "In essence this argument goes that without many QFs, the aggregate capacity value of as-available energy does not exist; hence no capacity payment is required.
>
> "This, of course, reduces the price paid to as-available QFs, thereby reducing the number of viable projects in strict conformance with well-accepted economic theory.
>
> "The ultimate result, of course, could be insufficient QFs ever to justify as-available capacity payments.
>
> "Now the converse to this argument is that if as-available capacity payments are made now, this may induce more QFs to come into being, thereby justifying these payments.
>
> "It appears that the choice of authorized payments revolves around the expectation of success or failure of the small power production program.

> "If success is expected, then as-available capacity payments are justified from the outset.
>
> "If failure is expected, these payments are not justified at the outset and could only be justified with later success of the program."

In view of the purpose of PURPA, Henwood argues that "success" should be a basic assumption underlying this decision.

Additional comments in this regard are offered by various nonutility parties.

We have quoted these parties at this length to indicate what we find to be compelling reasons supporting the "reduction in demand" model. Consequently, we will provide for capacity payments for as-available energy as part of the standard offer.

The "as available" capacity price we will adopt in this proceeding is based on the shortage concept as expressed earlier, which is based on the utilities' short-run marginal cost. The capacity then is consistent with "as available" energy payments, which are also based on short-run marginal cost. We agree with the parties who recommended that capacity payments be time differentiated, to reflect a higher price during peak periods when the possibility of shortages is greatest.

We are not dissuaded by SDG&E's legal argument that we lack discretion in this regard. As stated above, the standard rate must be "consistent" with the provision that certain specified factors shall be taken into account "to the extent practicable." One of the factors is:

> "(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system."

FERC plainly intends that aggregate capacity value be recognized.

We do not find that aggregate capacity has an equivalent value to firm capacity. To the extent that an individual QF is willing and able to contract to provide firm capacity additional costs can be avoided which should be reflected in the payment to the QF. These are provided for in the firm capacity offers presented below in which QFs receive full annual capacity payments based on specific performance commitments.

Having established the acceptability of a capacity payment for as-available energy, we now address the question of whether a QF producing electricity on an as-available basis is entitled to 100% of capacity value. If there is a capacity value recognized for as-available energy, staff recommends:

> ". . . initially a capacity payment be made in cents per kilowatt-hour assuming a 50% capacity value derived from full 25-30 year avoided capacity cost at 100% capacity factor. . . . That is, offers will be based on the assumption that every 2 kilowatts of installed capacity from intermittent sources provides for a flow of electricity which will allow the utility to avoid 1 kilowatt of capacity. The payment should be by time of delivery for large QFs and be at the option of the QF (depending on the meter the QF installs) for small QFs by either time of delivery or on an average basis."

As stated earlier, PG&E proposes that a 35% value be assigned. There is a wide difference of opinion among the parties regarding the resolution of this issue.

NRDC asserts that staff's recommendation undervalues QF contributions:

> "On the one hand, it could mean that a QF would receive a payment in cents per kilowatt-hour for the value of one-half of its installed capacity, op-

> erating at a 100% load factor. . . . However, the ambiguity of the wording could allow the interpretation that a QF would receive credit for only 50% of the capacity value actually provided."

It argues that QFs whose capacity factors typically exceed 50% should get corresponding capacity credit.

Several parties argue that the staff proposal is inadequate. Pan Aero Corporation (Pan Aero) argues that:

> "As to aggregate capacity value, the aggregate capacity value for as available capacity should be 100%, not the arbitrary 50% as recommended in the report.
>
> "Aggregate capacity should be prorated to cents per kilowatt-hour so that the full value is earned if the QF capacity factor is equal to the typical capacity factor of utility oil plants."

MPS agrees that 100% is the indicated capacity value and contends that even at that level QFs will be underpaid, "because of the inherent tendency toward daytime production possessed by all qualifying resources combined."

Metropolitan Water District of Southern California (MWD) argues that staff's proposal does not conform to FERC's intention that the fully avoided capacity cost be reasonably allocated, based on the QFs individual supply characteristics.

> "However, a reasonable allocation of the full-avoided capacity cost can be properly obtained through the staff's suggested option of time-differentiated capacity payments. Basically, this amounts to distributing the utility's full-avoided capacity cost by time period based upon a 100-percent capacity factor plant during each respective time period."

In this way the payments for capacity would be based totally on the performance by time period.

Edison supports the "pay for performance" concept which it contends renders unnecessary an assumed capacity value. Its proposed method is described as follows:

> "To be eligible for full capacity payment, a QF must attain a monthly capacity factor of 51% or greater by time period. The payment is based on the QF's monthly capacity factor by time period times the full capacity payment. Below 51% capacity factor, the capacity payment is reduced by 50%. The payment is then based on the QF's monthly capacity factor by time period times 25% of the full capacity payment, as the capacity factor of the QF increases or decreases, capacity payment increases or decreases proportionally."

This method is alleged to work regardless of technology.

SDG&E argues that the 50% aggregate capacity value is arbitrary and that it will be denied due process of law if such a value is adopted. It maintains its position that no capacity payment should be made.

The issue of the extent to which as-available energy will receive a payment for capacity value is inextricably related to the method used to estimate capacity value. Staff proposes that the capacity payments for as-available be in cents per kWh, by time of delivery and voltage, based on 25-30-year avoided capacity costs. SDG&E complains that there is no foundation for the assumption that QFs who supply aggregate capacity will do so for 25 to 30 years. It contends that:

> "To require current ratepayers to pay today's QF the value of a 25-30 year contract on the 'crystal ball' assumption that a new QF will replace him in the future to complete a 25-30 year term is

> again a blatant subsidy to the QF at ratepayer expense."

It argues that the length of the contract should determine the calculation of the appropriate capacity value.

PG&E proposes using the single-year capacity price, rather than the 25-30-year levelized price recommended by staff. It argues:

> "Our proposal results in a much simpler standard offer. If a single year value is used, there is no need for contract length, notice, termination or sanction provisions. If a levelized value is used, such provisions are necessary to recapture excess capacity payments if a QF fails to operate for the extended term. Under our proposal all QFs would be paid the correct amount regardless of the life of their project. A QF who operates for 30 years will receive the same life cycle payment as if he had been paid a 30 year levelized value. A QF who operates for 10 years will receive the same life cycle payment as if he had received a 10 year levelized payment."

Since the single-year capacity price changes each year, all QFs selling as-available energy will receive the same capacity price.

The consensus that does emerge from all of this is that the aggregate capacity payments should be based on performance, adjusted by time period. We agree that staff's proposed 50% value is ambiguous, arbitrary, and should not be adopted.

Instead we adopt a capacity payment for power from as-available sources equivalent to 100% of the shortage value of such power, as described in the following paragraph. This payment will be made in cents per kWh, will vary by time of delivery, and will be paid for each kWh

produced and delivered by the QF. Thus actual performance will determine the amount of the capacity payment.

As we have already discussed, the capacity payment we adopt on an as-available basis is based on a short-run avoided cost methodology. We will therefore not adopt the staff's recommendation of a forecast of future year capacity costs, but instead require utilities to use estimates of current shortage costs. For PG&E, in its most recent rate case, 100% of the annual capacity cost of a gas turbine was estimated to be the correct proxy for current shortage costs. PG&E allocated this capacity cost by time of day and time of year in a way that reflects the shortage cost incurred by marginal additions to load in each time period over the year. This approach would appear to be appropriate for our present purposes. Accordingly, PG&E, Edison, and SDG&E shall determine the as-available capacity price based on the 1982 estimated cost of peaking capacity (utilizing a combustion turbine facility as a proxy). Sierra shall determine the as-available capacity price based on the avoided (marginal) capacity costs as determined in the most recent case.

Costs should include generation and generation-related transmission. Contract length, notice, termination, and sanction provisions are not related to as-available offers, and should therefore not be included.

Aggregate capacity value will be available as a cents per kWh addition to the energy price only for energy delivered through a meter to the utility. The QF choosing the interconnection option of simultaneous purchase and sale will receive explicitly an aggregate capacity value for all energy generated, as the entire generator output is metered at the generator before any energy goes to the QF's load and to the utility. Under the sale of surplus power option, however, the meter at the point of interconnection with the utility will only measure that surplus portion of the generator's output which is delivered to the

utility after the QF serves its own load. Thus the QF will receive, in payments by the utility, only a portion of the capacity value for the total output of its generator. The remainder of the capacity value of the generator's output will, however, be recognized in the form of utility charges (including charges for capacity), which the QF will avoid by serving its own load.

There does appear in the record an issue regarding the appropriate capacity payment for small hydro facilities. Different treatment may be reasonable for hydro because of the probability that a large portion of the resource will fail simultaneously for an extended duration, limiting its aggregate value. The problem is compounded by a concern that hydro would be overvalued during wet years when capacity is relatively better than dry years.

The different points of view are summarized by Henwood:

> ". . . PG&E has proposed to use the absolutely worst year of record, 1977, to establish capacity values.
>
> "That naturally results in the minimum capacity value assignable to the hydro plant.
>
> "Staff, on the other hand, proposes to use the average of dry years.
>
> "Now, to my knowledge, there have been no conclusive studies ever performed which establish the best way to value hydro capacity in utility systems.
>
> "In fact, the Idaho Power Company plans capacity using the average hydro conditions, despite the fact that more capacity and more energy in their system comes from hydro than does in PG&E's system.

> "Since the industry itself values hydro capacity conditions nonuniformly, our recommendation is that much more thought, perhaps even in the form of a PUC or Energy Commission sponsored study into this area, should be given to the question before this very important and fairly permanent pricing treatment of hydro capacity contributions is set by the proceedings.
>
> "The other problem we see is when steam-flow gauging records are insufficient or unavailable, as is the case in many of the smaller projects being developed in California.
>
> "Of the seven projects our firm is currently involved in, only three have gauging records, and none of the projects have gauging records of a sufficient duration for PG&E's proposed 50-year water study."

We believe that capacity payments for as-available hydro should not differ from other technologies. Instead, as the methodology is perfected for calculating as-available capacity costs, the as-available payment should be low during wet years relative to dry years because the chance of shortages is lower in wet years.

Staff recommends the deletion of PG&E's Factor F-1, which makes adjustments to energy prices to small hydro QFs for the effect of hydro conditions on incremental heat rates and fuel inventory. PG&E argues that, if Factor F-1 is eliminated, its avoided cost prices would have to be increased. Its energy prices are based on forecasted avoided costs which do not consider cost impacts due to variations in hydro conditions. QFs generally oppose the imposition of Factor F-1.

We conclude that Factor F-1 should not be allowed. We are not convinced by PG&E's arguments that its computation of avoided costs should be modified by the elimi-

nation of Factor F-1. These arguments should be considered together with a complete examination of the computation of marginal energy costs in the compliance review to follow. Because most small hydro projects are in the planning stage, this delay will not have a significant cost impact to PG&E.

c. Long-Term Contracts

i. Energy

The FERC provides the seller of energy with the option of payments based on either (1) avoided costs calculated at the time of delivery, or (2) avoided costs calculated at the time the obligation is incurred. Payments under the first option should be the same as payments for as-available energy, as provided above. Payments under the second option require long-term energy price offers.

A major issue in this proceeding is the terms utilities should provide to QFs for commitments to deliver energy in future years. In this section we will discuss the issue of establishing a price for the energy portion of avoided cost based on a forecast of energy rates in the future. Many argued that utilities should commit in advance to future energy rates, and further recommended that the Commission order a levelized payment option as well.

A long-term energy price offer allows both a QF and the utility the certainty of a known price which can be valuable for planning. We therefore will order utilities to file a proposed price offer which commits both the utility and the QF to energy payment prices for up to five years, based on a forecast of the utilities' variable costs. Under such an offer, the QF must commit to provide all the energy it produces to the utility over the contract period. We will order the offer to be a proposal for review in hearings by other parties before it becomes effective. This price offer will be available to all QFs.

Staff proposes that the QF be allowed the further option of levelizing the price so that a greater portion of the total payment is received in the early stages of the contract. FERC comments addressing this provision expressly provide for the levelization option:

> "A facility which enters into a long term contract to provide energy or capacity may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or nonregulated electric utility from approving such an arrangement."

Thus we have the discretion to provide for levelized payments as part of the standard offer.

Edison opposes levelized energy payments. It characterizes the necessary estimates as "purely speculative", and not reliable. It argues:

> "Paying levelized costs for an increasing cost stream is unfair to present ratepayers because it results in paying for a benefit before that benefit accrues. Even five-year levelizing has this effect, and the proposed ten-year levelizing, coupled with the total inability to accurately predict future fuel costs, represents an impermissible burden on ratepayers and is not necessary to encourage QF development."

Edison proposes that if levelized payments are required, the payments should not be allowed to exceed 85% of

avoided energy costs levelized over a period of not more than three years.

PG&E also opposes levelized energy payments because it "presents too many risks" for the ratepayers. It agrees that if the Commission requires such payments, a reduction from the avoided cost should be authorized. It further recommends:

> "Energy contracts under such circumstances should be limited to an appropriate term. This will reduce exposure to forecast uncertainty and early termination due to a QF's failure to perform. The potential overpayments using levelized energy prices are enormous, and in the event of early termination, large sums will have to be recaptured from the QF."

The problem increases as the length of term increases.

PG&E also recommends that levelized payments not be available to cogenerators using oil or gas.

> "Because of the high operating costs of these facilities, the QF's revenues must escalate to track the increasing project fuel costs. If a levelized energy payment is available to QFs using oil or gas, it is likely that those QFs will begin incurring operating losses before the end of the contract life."

It warns that QFs will not continue to operate merely because they made excess profits in the early years of their projects.

PG&E does not necessarily oppose all forms of levelized energy payments. It proposes that in the case of nonstandard contracts, it can assess the ability of the QF to perform over the duration of the levelization period and provide for such payments if appropriate.

SDG&E also opposes levelized payments. It warns that "levelized energy payments will result in up front financing as overpayments will occur in the early years."

Several nonutility parties support levelized payments. California Energy Commission (CEC) analogizes levelized payments to insurance contracts, and argues that ratepayers and QFs both benefit, assuming forecasts are reasonable. Ratepayers

> ". . . cannot gain if costs are less than forecast, but they are also protected from higher avoided costs than with forecasted and protected from consequent economic losses.
>
> "This isn't putting a risk on the ratepayers. It is giving them certainty. At the same time it also protects the QFs.
>
> "The QF doesn't gain if the utility underforecasts and oil prices are actually higher, but the QF is protected from losses if the utility overestimates future costs."

CEC does agree with PG&E that levelized payments should not be made to QFs using oil or gas as a fuel.

Levelized payments are also supported by the jointly filed comments of Great Western Malting Co. and Windfarms, Ltd. (Great Western). They consider such payments "critical" to some QF's for financing purposes. They oppose the discounted payments proposed by the utilities:

> "The utilities' argument that levelized energy payments should be discounted incorrectly assumes that the risk that levelized payments will inaccurately forecast actual energy costs falls solely on utilities or their ratepayers."

They contend that the QF also takes a substantial risk that actual costs will exceed estimated costs.

They further object to the argument that a discount is appropriate because large numbers of QFs will not fulfill their contracts. They characterize this premise as based on unsupported assumptions.

We conclude that levelized payments should not be included as an option under the standard offer. We recognize that levelized payments can encourage QF development by improving QF access to financing, and therefore consider this type of payment schedule to be desirable in some cases. However, because levelized payments can create added risks for ratepayers and because the magnitude of this risk depends completely on the specific QF project in question, we find that levelized payments are more appropriately considered by the utility and, if necessary, the Commission on a case-by-case non-standard contract basis.

Levelized payment schedules create potential risks to ratepayers that are not present in other types of long term QF contracts such as that adopted above. In the process of paying the QF prices in excess of avoided costs in the early years of the levelized contract, the utility and its ratepayers bear the risk of contract non-completion due to project failure. If a contract is terminated early because of project failure, the ratepayers will have paid costs in excess of the value of the power received and will not receive that countervailing benefits that would normally accrue during in the later years of the levelized contract. The degree of such project risk that is actually present can be expected to vary significantly from one QF to another, and will depend on the technical and economic characteristics of the specific QF project. Therefore, it is not appropriate to offer this payment option on a uniform basis to all QF's under a standard offer that is deemed *per se* reasonable for ratemaking purposes. Rather, such risks should be considered by the utility on a non-standard contract basis after review of the specific QF project in question. If necessary, such contracts can receive Commission scrutiny under our non-standard review process.

The non-levelized energy payments under the long term energy price offer described in this section may be tied to either as available capacity payments provided for in the last section, or to a firm capacity payment using a short run avoided cost methodology, which we will describe next.

ii. Firm Capacity

As stated above, FERC regulations provide for payments for firm capacity, based on avoided costs calculated either at the time of delivery, or at the time the obligation is incurred. There is no hesitation on the utilities' part to pay for firm capacity, within the limitations of their own resource plans. For standard offer purposes firm capacity is properly recognized as an "increase in supply" with corresponding standards, termination provisions, and sanctions.

The firm capacity payment properly reflects the factors recited in Part IV, A, above related to the availability during the system peak periods, including:

a. Dispatchability,

b. Reliability,

c. Contract duration, termination, and sanctions,

d. Scheduling of outages, and

e. Availability during emergencies.

The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage that development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollar per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment.

The firm capacity contract may be tied to energy payments as-delivered (similar to the energy payment in the as-available section) or to a contract for energy payment in future years as provided in the previous sections. The firm capacity payment discussed in this section is based on a short-run marginal cost methodology, in which the capacity payment reflects the costs of a shortage.

Both the firm and the as-available capacity payments ordered by this decision are based on the shortage cost concept. However, QFs with firm capacity contracts may receive a higher payment than QFs with as-available contracts. For example, a QF with a firm capacity contract that operates with a capacity factor similar to utility plant could receive the full annual capacity payment. As-available QFs would receive only a percentage of the annual capacity value for similar performance because the annual capacity payment is allocated in cents/kWh for as-available capacity.

The value of firm capacity will be based on the avoided (marginal) capacity cost used in the utility's last general rate case.

As discussed above, FERC allows for the option of levelized payments if the QF chooses payment based on avoided costs calculated at the time the obligation is incurred. The option for levelized capacity payments for periods up to 25 to 30 years as currently offered, should remain.

Dispatchability will be achieved in price offers by time basing capacity and energy prices and by requiring the QF to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment or fuel, water, wind or other source of energy supply. Cogenerators also

will, at times, have limitations on their ability to utilize the process heat produced at maximum capacity.

For receipt of a firm capacity payment, reasonable contractual requirements for reliable operation and availability during utility system peak load periods are necessary where QFs are to receive the full avoided cost capacity value. Contractual requirements must, however, be simple and not restrictive to the point of seriously discouraging QF development. QFs should not be expected to operate with a reliability greater than the utility plants they displace. Likewise, the QF can be required to maintain an availability during system peak and mid-peak load periods comparable to, but not greater than, utility plants displaced. Where resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure to use in contractual requirements for reliable operation.

In discussing rates for supplementary and maintenance power, we determine that demand charges incurred during periods of scheduled maintenance should be waived during such periods under tariff schedules for standby service. It is waiver applies to QFs selling surplus power to the utility. It is reasonable for a utility purchasing firm capacity from a QF to require that the QF schedule maintenance of that generation during periods established by the utility. The utility will provide reasonable periods for QF scheduled maintenance and only request deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments will not be reduced during scheduled maintenance periods. QFs on simultaneous purchase and sale contracts will continue to pay for any energy (kWh) and demand (kW) used during scheduled maintenance periods at regularly filed tariff rates.

Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability. Two options shall be offered hydro QFs

larger than 100 kW for determining their base stream flow and monthly firm capacity rating. Option 1: the QF may use flow data directly applicable to the QF's facility, when available. Alternately under Option 2 the QF may use the flow data for the closest adjacent and similar area to the QF's facility. Capacity values for Option 2 shall be developed by areas sufficiently limited in size so that the true value of local areas is not lost or obscured. Capacity values for Options 1 and 2 shall be paid in dollars per kW per month and shall be subject to the provisions required for firm capacity.

For Options 1 and 2, the minimum June through August flow, from which the monthly firm capacity rating is derived, will be based on the five lowest flow years, as proposed by CEC, taken from a 50-year minimum continuous record. Where 50 years of data cannot be developed, utilities and QFs should agree upon a shorter time period with fewer minimum flow years averaged into the monthly capacity rating.

The price offering for small hydro QFs should include an illustrative example of the development of monthly firm capacity ratings based on dry years stream flow data. The price offer will also specify the data on stream flow required by the utility.

In its preliminary report staff recommended that utilities be required to provide QFs the option of a full capacity payment "up front", because the utilities would make such investments in the absence of QF development. The reaction of the parties was mixed. In its final report staff recommended that up-front capacity payments not be required as part of the standard offer.

Several parties continue to support up-front payment. The California Manufacturers Association (CMA) suggests that:

> ". . . in some cases it may also be appropriate to provide the QF the option of an up-front payment. An equitable method would be to place these payments in rate base amortize them over the life of the contract, and remove them from rate base using the same standards and procedure for removal of utility plant."

The risk for the utilities would be largely eliminated.

CEC originally supported up front payments but, like the staff, changed its position. The utilities unanimously object to up front payments, arguing generally that the resulting financial outlays would strain their financing abilities while imposing an additional risk relative to the capability of a QF to perform.

Staff considers this issue deserving of further study.

> "The complexities of the issue of up front capacity payments deserve additional research before such payments are required as options in standard price offers. This research will accomplish such objectives as identifying and analyzing: (1) the conditions under which such payments would financially strain utilities; (2) the implications of putting such payments in rate base; (3) the juxtaposition or fairness of the utility being somewhat like an owner (having paid the utility's avoided capacity cost which may pay most or all of the QF's capital investment costs) but not having control of the facility's management or operations; (4) the actual usefulness of up front capacity payments since such payments as now proposed would be at the first operation of the QF (after construction and financing are complete); and (5) the proper assessment of risk (such as QF risk from proper avoided cost calculation, recognition of only the risk to ratepayers of QFs,

> or a net assessment including the risk to ratepayers of utility operations)."

In the meantime staff expects utilities to develop prudent alternatives to the standard offer and suggests that innovative proposals be considered by this Commission in its evaluation of utility efforts to develop alternate energy sources.

We are satisfied that up front capacity payments are not reasonably included as part of the standard offer. We agree that such payments could introduce an element of substantial risk into the standard offer. Since the QF has sole choice among the standard offer provisions, the utility would be precluded from exercising discretion regarding the suitability of a particular QF in regard to its ability to perform. Such discretion is critical to orderly undertaking of such risks.

Such payments are reasonably considered outside the context of the standard offer. Utilities are free to agree to such provisions on a negotiated basis and to seek whatever ratemaking treatment may be shown to be reasonable. There is no need for additional study of this issue.

iii. Energy and Capacity: Long Run Marginal Cost

Several parties addressed the problem of matching together the appropriate energy and capacity payments to ensure the QF is paid the full avoided cost. This issue is of particular concern to QFs that wish to enter into long-term contracts without ending up in a situation where their payments are based on a combination of today's low capacity cost (based on a gas turbine) with low energy costs in the future (due to new baseload generation). The problem is discussed by staff, but in the opinion of Dr. Harry Davitian, representing the San Diego Energy Recovery Project (SANDER):

> "To phrase the problem with the staff's approach in its simplest form, there is no connection made

> between the computation of avoided energy costs and the computation of avoided capacity costs, even though in actuality there is a direct relationship."

Davitian contends that since utilities are emphasizing the construction of capital intensive, low variable cost capacity, the bulk of the costs avoided in the future will be related to capital investments in the purchase of capacity, not to variable costs. A computational approach that does not adequately reflect such savings in capacity costs will not provide the proper pricing signal to cogeneration and small power-producing facilities.

Davitian asserts that the staff's approach is impossibly vague. He proposes a method called a "differential revenue requirement approach", which he describes as follows:

> ". . . the utility's total annual costs, including all fuel, operating and maintenance costs, capital amortization, taxes, etc., are estimated, both with and without a projected contribution of power from the qualifying facility or type of qualifying facilities.
>
> "The difference in the two costs is directly attributable to the contribution of power from the qualifying facilities.
>
> "To properly account for the changes that might occur in the utility's capacity purchases, purchase power agreements, sales of power agreements and the associated changes in energy costs, a capacity exchange model is used in this type of calculation.
>
> "In each year of the study period, a differential cost can be established and can be expressed in terms of cents per kilowatt-hour of power provided by the qualifying facilities."

The energy and capacity components of the avoided costs can then be derived.

Great Western also complains that staff's proposed methodology is not adequately explained. It offers its own proposal for matching energy and capacity:

> "Capacity payments, on either an as-delivered basis or by contract, should reflect the avoided costs of a utility building a plant solely for capacity, i.e., the avoided cost of a combustion turbine or combined cycle facility. This sort of a plant would remain the yardstick for the capacity payment throughout.
>
> "The energy payment should be made up of two components. First is the utility's avoided running costs for its marginal plant - the costs of fuel, operations and maintenance, etc. Second, if the marginal plant in the utility's resource plan is something other than a low capital cost combustion turbine, the additional capital costs of that plant, over and above the capital costs of a combustion turbine, should be allocated to the energy payment. This accurately reflects the fact that, when a utility expends the additional capital necessary to construct a coal-fired thermal plant, for example, it is doing so not simply to build capacity but to reduce future energy costs. If the utility simply wanted to build capacity, it would build a low capital cost combustion turbine. The additional capital spent should therefore be considered an energy cost. Thus, if this additional capital expense is avoided, due to the fact that QFs are generating electricity, that fact is properly reflected in the energy payments to QFs."

In addition to linking energy and capacity payment, this method is alleged to reflect a utility's actual resource plan and therefore its actual avoided cost.

As we discussed in the introduction to this section, we stated that avoided costs can be developed based on a short-run concept or a long-run concept. Either concept is appropriate for developing standard offers assuming suitable terms and conditions are associated with the offer. The offers discussed thus far in this decision are based on short-run avoided costs. Because of the concern of the parties that short-term avoided cost may be too volatile, and may not adequately reflect the QF's value in the utilities' long-range resource plans, we acknowledge the desirability of an offer based on long-run avoided cost principles. Therefore, we will order utilities to file a proposed offer using long-run avoided costs within 90 days of this decision date.

In order to assure full examination of alternative approaches in the evidentiary proceeding, PG&E, Edison, SDG&E, and PP&L are directed to develop avoided costs and a price offering based on their resource plans. The cost data and price offering should allow up to a 25-year contract with a firm pricing structure for capacity and energy. Long-run marginal cost estimates will be based upon the fixed costs associated with the utility's resource plan and its system projected marginal operating costs. The recommendations of Davitian and Great Western are also to be analyzed by the utilities and discussed in their presentation.

iv. Bond guarantees

CEC argues that the standard offer should also provide for cost-based bond or loan guarantees.

> "A cost-based loan or bond guarantee is a contingent liability undertaken by a utility at its cost which guarantees the repayment of a bond or loan for a (QF). Given the utilities' size and position in the typical power sales agreement, they can 'package' projects that need these guarantees for 'reinsurance' with other investors, or self 'in-

> sure' with sinking fund type accounts levelized over the project.
>
> "Bond or loan guarantees may be the only way in which many municipalities and smaller developers will be able to get their projects financed and constructed. This is due, in part, because of the impossibility of marketing bonds, particularly municipal bonds, even for economically justified projects, without guarantees for the debt from some organization recognized as financially acceptable by the financial community."

It warns that without such "standardized" terms the utilities will "negotiate" discounts from their actual costs.

The CEC's proposal is one of many conceivable financial arrangements which could assist development of qualifying facilities. The problem with adopting such a loan as part of the standard offer is that the risks associated with the loan guarantee will vary by project, making it impossible to fairly standardize terms. For this reason, we will not adopt the CEC's proposal as part of the standard offer, but rather allow such proposals to be negotiated as non-standard offers. With existing avoided costs offered as a foundation for negotiation between utilities and QFs, we believe these negotiations can be undertaken fairly.

d. Zero Capacity Payments

Staff raises the following issues in regard to zero capacity payments:

> "Do utility price offers which make no payment for capacity in the first few years of the 1980's reflect the ability of the utility to avoid costs? Are they reflective of the shorter lead times available with additions of capacity from OFs? Are they just and reasonable?"

Staff concludes that costs are actually avoided each year. Reasonable calculations of actual avoided cost would in-

clude the following: identified plant, reserves, power pool prices, shortage costs, opportunity costs, and replacement costs. Therefore, "capacity rates for purchase matrices will contain no zero values (rare instances excepted), or blank entries."

Edison agrees that rates for purchase of capacity should be based on "actual avoided costs", which:

> ". . . may result in zero capacity value during the initial implementation period of this OIR No. 2 due to prior planning commitments, as well as during some future situations when capacity purchases would be to the disadvantage of ratepayers."

It argues that short-term QF contracts are not conducive to the development of reliable and efficient generation resources and result in unnecessary risks. It suggests that staff ignores facts and asks: "How can the staff seek to require a capacity payment to a QF when the added capacity is of no value to the customer?" Zero capacity payments are alleged to be sometimes necessary to be fair to the ratepayer.

SDG&E agrees that "capacity benefits are never exactly zero." However, it relies on a quote from United States Supreme Court Chief Justice Warren Burger to support the proposition that such a determination is "of an adjudicative character" and can only be made in an evidentiary hearing.

PG&E supports the staff recommendation.

The issue of whether zero capacity payments are ever possible is better understood consistent with the distinction between short- and long-run marginal cost presented earlier. For short-run marginal cost, the capacity represents the costs associated with the possibility of a shortage. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment

always has some positive value. Assuming that the firm contracts offered by the utilities are tied with a utility's short-run energy cost (implying a short-run avoided cost concept) those contracts should always include a positive capacity payment though it may vary depending on the probability of a shortage. We conclude that a capacity value should exist for a one-year contract executed at the beginning of the year of delivery. This value should be the avoided (marginal) annual capacity cost based on the 1982 estimated cost of peaking capacity. This value should be available to QFs executing firm contracts on a $/kW and c/kWh basis similar to longer term contracts.

e. Refusal to Purchase

FERC regulation Section 292.304(f) provides, in part:

> "Periods during which purchases are not required.
>
> "(1) Any electric utility which gives notice pursuant to paragraph(f) (2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did make such purchases, but instead generated an equivalent amount of energy itself.
>
> "(2) Any electric utility seeking to invoke paragraph(f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility."

FERC states that this provision does not override "contractual or other legally enforceable obligations" of the utility to purchase from a QF and that such nonpurchase periods may be taken into account in setting rates for

purchases. There is widespread interest in the way this provision will be reflected in the standard offer.

Staff offers a series of recommendations. It proposes that utilities not be allowed to refuse to purchase energy or capacity which is fixed by contract over a duration of obligation, except for conditions of emergency, maintenance, or minimum load. As an alternative, staff suggests utilities may offer the actual lower avoided costs to QFs if actual avoided costs are lower than those sufficient for as-available deliveries. Under the alternative the utility must accept all deliveries tendered by the QF and offer the actual lower avoided cost. Utilities will be limited to 600 hours per year of paying a price lower than the published avoided cost price or refusing deliveries under conditions of maintenance or minimum load. Utilities that choose to pay lower prices would be required to pay prices higher than the published avoided cost price when actual avoided costs are higher than the published price for up to, but no more than, 600 hours per year.

Staff further recommends that utilities propose a notification procedure that will provide adequate notice to QFs of times of nonpurchase and prevailing prices. A list of periods of anticipated nonpurchase is suggested so that QFs would be able to schedule maintenance to coincide with such periods. A minimum of 48 hours notice is proposed for QFs with baseload or intermediate-type plants. A minimum of two hours notice is suggested for QFs with peaking-type plants.

Nonpurchases are proposed to occur in the following order of priority: first, small power producers who can inventory fuel; second, topping cycle cogenerators who can bypass the electric generation and save some fuel; third, bottoming cycle cogenerators and small power producers where fuel cannot be stored.

Staff further proposes that each utility be required to present a report in every ECAC proceeding explaining and

supporting periods when prices are lower than published or when nonpurchase occurs.

PG&E proposes:

"Utilities shall not be required to accept power from QFs during (1) emergencies; (2) times of pre-announced maintenance on the utility system which are limited to the shortest possible duration; and (3) operating conditions of minimum load on utility plants, the continued operation of which is necessary to serve anticipated daily load swings. Such minimum operating conditions include operation of geothermal facilities, utility dispatched hydro-electric facilities and firm purchases to obtain optimum use of these resources.

"To account for the availability of economy energy, which is energy purchased by the utility at a price below the Standard Offer published prices, utilities may either:

"a. Calculate their avoided energy cost to include an annually expected number of hours of economy energy. During periods when economy energy is available, the utility shall not refuse to accept QF energy deliveries based upon price; or

"b. Offer the lower avoided cost price to QFs when economy energy is available and only curtail, and not pay for, energy and As-Delivered Capacity (if the QF has chosen that option for capacity payment) made available by a QF which refuses to accept the lower price."

It would limit the number of hours of nonpurchase or lower prices to 600 per year.

PG&E also agrees that a report should be filed in ECAC proceedings (though not as detailed as proposed by staff)

and with staff's recommendations regarding notice to QFs and priority of refusal to purchase.

Edison states that it is concerned with the possible impact of paying published avoided costs to QFs when lower cost energy is available. It indicates that during such periods, the lower cost energy may be substantially below the cost of energy produced from the low sulfur fuel oil. It warns that a utility would be severely criticized if it were unable to meet its public utility obligation to its customers to provide lowest cost power, and an unjustified burden would be placed on the utility shareholder if the avoided cost payments were not recoverable in an ECAC proceeding. It concludes that payment at prices below published avoided cost, when its true avoided cost is less than the published price, is consistent with PURPA and FERC regulations.

SDG&E contends that "if the energy payment tables are properly calculated, the actual avoided costs to the QFs will be properly reflected and paid." It suggests that the problem of nonpurchase for economic reasons can be resolved through proper costing periods. By adopting a "super off-peak" reflecting anticipated periods of low cost energy, the times when avoided cost energy rates would be so far out of line with actual avoided costs to justify refusal of deliveries would be minimized.

SDG&E does support the ability to pay at less than published costs for certain maximum hours during the year, and accepts 600 hours as reasonable.

SDG&E states that staff's recommended notice requirement is "excessive". It offers two-hour notice for baseload and 30-minute notice for peaking units as "more realistic." It also objects to staff's nonpurhcase priority. It argues that "curtailments must be based only on size, from largest to smallest. In an operational emergency, it is impossible to spend time deciding who has fuel capabilities and who does not."

In general, we find that the utilities have interpreted this provision more liberally than apparently intended by FERC. The language of the regulation expressly limits its application to periods when the choice is between a QF and self-generation. There is no recognition of economy energy purchases.

This interpretation is supported by FERC comments:

> "This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when system demand later increased. As a result, the utility would be required to utilize less efficient, higher costs units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output."

This concern does not appear to contemplate economy energy purchases.

This issue must be addressed in the context of the standard offer options described above. The QF may contract to be paid on the basis of "the avoided cost calculated at the time of delivery." The right to not purchase arises only when that cost is less than zero, a negative avoided cost.

The QF may instead contract to be paid based on "the avoided costs calculated at the time the obligation is incurred." This method yields the sort of "published prices" apparently referred to in the various comments. There is no basis for refusing to purchase from such QFs merely because actual avoided costs occasionally go below pub-

lished prices. There is just as much of a chance that actual avoided costs will be occasionally higher than published prices. Allowing for nonpurchase in the first instance without providing for a higher payment when appropriate is unfair. Providing for both higher and lower payments is inconsistent with the purpose of the option to be paid based on avoided costs calculated at the time the obligation is incurred. Therefore this QF should be refused electric purchases only when the avoided cost is negative.

QFs have expressed concern that there may be no maximum number of hours during which refusal to purchase energy may occur. They feel this may result in financing problems (among other problems) since the utilities then are viewed as having an open ended opportunity to refuse purchases. A refusal to purchase would, of course, be subject to Commission review as provided by FERC. A more pragmatic method is require to allay these concerns. First, this decision will order that refusal to purchase, except in cases of emergency and scheduled maintenance, shall be limited to QFs of 1 MW or larger. Second, a refusal to purchase should only occur when a negative avoided cost occurs. Refusal to purchase should only apply in certain narrowly defined circumstances, unlikely to occur more than 100 hours per year.

Staff earlier recommended limiting the periods when a utility could pay a lower price or refuse to purchase to a time period "up to 600 hours" per year. Since the avoided cost price will reflected estimates of periods when avoided costs are higher or lower due to low load and high availability of hydro, periods need not be allowed during which a lower price is paid. In fact, FERC rules do not appear to allow utilities to pay a lower price during selected periods.

The earlier 600-hour limit stemmed from a PG&E estimate of the maximum number of hours in a high rainfall year that their hydro plants would otherwise need to be

curtailed and spill water. FERC rules require that the utility experience a negative avoided cost situation to permit nonpurchase. However, a negative cost would not occur when a utility curtails its own hydro. There remain few instances where negative costs would occur. For example, if a baseload or a large oil-fired intermediate load plant were shut down at night, due to an excess of QF electricity, but then could not be restarted and brought up to its rated output for the next day's peak load, and necessitated instead startup of a plant with very high generating costs (e.g., a gas turbine peaker or an expensive emergency purchase of capacity), the cost to meet the day's peak load might substantially exceed the avoided cost of the previous night's shutdown, thus giving a "negative avoided cost". A proper generating mix, including intermediate load plants of various sizes and possessing the ability to be throttled and even cycled should, in most cases, prevent occurrence of a negative avoided cost situation. It is recognized, however, that QFs need assurance at the outset of a reasonably small time period for nonpurchase. While no limit is specified herein, we do not think refusal periods, as defined, will be more than 100 hours per year and we will monitor utility actions.

FERC provides for effective notice to the QF so that the QF has ample time to cease delivery. In this respect we consider SDG&E's proposed two-hour notice to a baseload facility inadequate. The notice proposed by staff and PG&E is reasonably fair to the QF while remaining within the utility's planning horizon. No recovery will be allowed for payments resulting from insufficient notice unless the utility proves it was unable to provide greater notice, and that it attempted to make economy energy sales of the QF's power. We agree that QFs should be assigned priorities, in anticipation of the possibility that only partial restriction would occur. Staff and PG&E propose establishing priorities by technology. SDG&E proposes that size determine priority.

We are not persuaded by SDG&E's contention that it cannot consider fuel capabilities at the time of nonpurchase. We suggest that the time to consider such matters is during normal operating conditions when a priority scheme can be developed for later use. Refusal to purchase by size would be no more workable. The ability of the QF to function independently during times of nonpurchase is entirely the responsibility of the QF.

Thus we adopt staff's proposed priorities with modifications to reflect the more limited conditions we have established under which purchases may be refused. Specifically, while we recognize that an advanced notice of 48 hours for QFs with baseload or intermediate plants and two hours to QFs with peaking plants is a reasonable criterion there may be situations where 48 hours' advanced notice is not possible.

The notification procedure serves a second purpose. It also alerts the utility of a pending condition that should direct it to consider the opportunity to make economy energy sales. Before refusing to purchase from a QF, the utility should undertake to make such sales on behalf of the QF. We expect that the utility will undertake prudent planning to prevent negative avoided costs from occurring. The negative impact associated with the below minimum load condition suggests that prudent planning would entail arranging for economy energy sales as a margin of safety.

One distinction does arise between QFs for nonpurchase purposes, related to the particular form of standard offer. There is no capacity obligation during times of nonpurchase for as-available contracts. The obligation to pay for capacity during these times applies only to firm capacity contracts.

The orderly review of the application of these procedures requires that a report be filed by each utility in conjunction with its annual ECAC review. Utilities without ECAC proceedings will file an annual report no later than

each January 31 to cover the preceding calendar year. In this regard staff proposes that the report include at least the following:

a. The hours and duration of nonpurchase;

b. The amount of energy not purchased;

c. The utilities to which the electricity was offered for sale;

d. The prices at which the electricity was offered for sale;

e. The prices at which the neighboring utilities were willing to buy the electricity;

f. The QFs whose power the utility refused to purchase;

g. The lower prices offered to the QFs which the QFs refused;

h. A statement from each QF certifying the QF was notified within 48 hours for a baseload or intermediate QF and within two hours for a peaking QF, and that the QF actually refused the lower price;

i. The operating conditions under which the utility invoked the refusal to purchase and which required the refusal; and

j. A statement from each neighboring utility explaining their operating conditions at the time of the refusal to purchase which prevented them from taking the electricity at some mutually acceptable price.

PG&E and SDG&E object to various provisions as excessive and burdensome.

Paragraphs (h.) and (j.) do provide for information not in the control of the reporting utility. To that extent we

agree with PG&E and SDG&E that such information should not be required. In addition, ascertaining the exact amount of energy not purchased, as called for in Paragraph (b.), may prove difficult; therefore, estimates of these amounts will be sufficient. We also decline to adopt the staff's position which led to the recommendation contained in Paragraph (g.). However, the remaining items relate to data that is in the control of the utility and that should be gathered in the ordinary course of its business. There is no apparent hardship related to providing such information, at least during the early stages of QF development. We will require inclusion of these items in the annual reports. The report should also state the hours of advanced notification given each QF for each nonpurchase and, in cases where the prescribed minimum notice was not given, an explanation of why more extended notice could not be given.

f. Simultaneous Purchase and Sale

Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. It is intended to respond to the situation where the retail rate is less than the avoided cost, by providing that the QF receives the full benefit of avoided cost pricing principles. The QF is not required to separate its load from its resources to qualify. The electricity flow is the same regardless. The difference is cash flow. Staff recommends that the QF have the opportunity to convert to and from simultaneous purchase and sale as it deems necessary, to protect itself from further regulatory and utility changes and future rate and tariff changes.

PG&E warns that indiscriminate switching between options by a QF will place unreasonable burdens on the utility. It agrees that the right to convert is reasonable if the following procedures are applied:

"1. The QF will be subject to the terms and conditions of all applicable filed tariffs and contracts in effect covering the existing and proposed facilities used to serve and/or interconnect the QF's project.

"2. The QF will be required to reimburse the utility its out-of-pocket costs, with appropriate credits, resulting from any change in the utility's facilities required to accommodate the QF's change in sales option. Increased or decreased interconnection and service facilities will usually require new agreements and result in an adjustment of charges to the QF to meet such new requirements. Where the QF's switching of sales options will render the utility's facilities idle in whole or in part, the QF may elect to do one of the following: (1) pay the utility to rearrange its facilities to meet the new and reduced requirements, or (2) with the utility's approval, pay the utility to reserve any excess capacity in its facilities. Such charges will be in addition to any other utility charges applicable to the QF's new service requirements.

"3. The QF will provide the utility with reasonable and appropriate notice of its new requirements brought about by any switching in sales options in order to allow the utility adequate time to accommodate the QF's request."

It provides an example that illustrates its proposal.

SDG&E agrees that simultaneous purchase and sale is a required option, but takes a much less flexible view regarding switching. It proposes that the QF make the election at the time the contract is made and that no switching be allowed. It argues:

> "If no election were required at the one time of execution the utility would be unable to forecast sales and revenues in a general rate application. It seems unlikely that a filing which contains substantial sales variances depending on how the final revenue is allocated, would be acceptable to the Commission.
>
> "A failure to make such a firm election would also allow any QF to at least partially thwart Commission policy being implemented in these rates. For example, had this policy been in effect when the Commission ordered implementation of Time-of-Use rates, the QF could have avoided such rates by ceasing to sell and using its own generation. SDG&E supports the position that any customer can avoid Commission policy by generating for his own use. However, a QF who wants to take advantage of Commission purchase policy through simultaneous purchase and sale should be subject to Commission policy on the sale side as well."

It contends that allowing the QF to switch results in an unreasonable burden on other ratepayers and the utility.

We agree with the staff in principle that the QF should be able to convert to and from simultaneous purchase and sale unless the QF has selected forecasted or levelized energy payments under a long-term contract. In such cases, the QF must commit its entire output to the utility. Conversions should be limited to once per year as is currently the practice under Rule 12 for changing rate schedules.

We agree with PG&E that in practice the conversion must be conditioned on reasonable notice and full compensation. Notice requirements should not be excessive. However, if the interconnection and metering installed for selling surplus power are not compatible with simultaneous

purchase and sale, a longer delay may be necessary for conversion. The QF may also encounter additional interconnection costs if conversion of the original wiring and metering is required. The QF that pays for a more costly interconnection and metering arrangements under simultaneous purchase and sale and then converts to selling surplus power would not be able to recover the additional costs except in terms of a salvage cost. The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions.

g. Exceptions

The foregoing discussion addresses the matter of the terms of the standard offer to be applied to facilities of more than 100 kW. There remains the matter of how these principles will apply to Sierra and Pacific Power & Light company (PP&L).

We discussed earlier Sierra's concern that QF production causes certain potential problems because of its size, location, and configuration. We consider the import of its position to be that its actual avoided costs are susceptible to substantial fluctuations depending on the number and size of prospective QFs. This problem is best resolved by excusing Sierra from the obligation to provide a standard offer to QFs of more than 100 kW. Instead, Sierra will be allowed to contract with each on a nonstandard basis that reflects the actual costs avoided by each QF consistent with the avoided cost principles in this decision.

PP&L asks for some from of exclusion or waiver from some portions of the final staff report and this decision. It contends that PP&L is "entirely unlike the model utility that is assumed to exist in the staff's final report." It argues that "the utility assumed to exist is an oil-fired geographically centralized utility, one that uses oil as a primary source of energy, one that serves a relatively

centralized and contiguous territory." It cites a number of factors that distinguish it from the others.

We agree that PP&L is different in material respects. We therefore order the utility to propose a standard offer for review by parties based on its avoided costs. We will determine what additional action to take after reviewing its filing. We will not order the utility to adopt the specific standard offers filed in this decision at this time.

3. Standard Rates For 100 Kilowatts or Less

FERC Regulation Section 292.304(c)(1) provides:

> "There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 10 kilowatts or less."

Such standard rates must be consistent with the specified factors affecting rates for purchases and may differentiate among QFs on the basis of technologies.

Staff recommends that standard rates for QFs of 100 kW or less should be simple, paying for both energy and capacity in cents per kWh. Staff proposes that the rates be either time or non-time differentiated, at the QF's option. As with the larger QFs, staff suggests that the capacity payment be based on an aggregate capacity contribution of 50% of the full 25-30 year avoided capacity cost at a 100% capacity factor, regardless of technology. Transmission and distribution avoided costs and losses would be paid to QFs choosing simultaneous purchase and sale.

The utilities respond in much the same terms as with regard to the standard offer issues related to larger QFs. PG&E proposes that the capacity component of the prices should be based on an aggregate capacity contribution of 35% (as opposed to 50%) of the full one-year avoided capacity cost. SDG&E does not agree that the capacity por-

tion of the rate should be paid on a cents per kWh basis for both time and non-time differentiated deliveries. It objects to any capacity payment method that makes substantial payments on a non-time differentiated basis. It characterizes staff's proposed 50% value as an arbitrary gratuity at the expense of the ratepayers. Edison complains that staff's recommendations reflect staff's improper attitude toward the avoided cost concept. Edison repeats its contention that costs cannot be deemed to be avoided.

We agree that the standard rate for small QFs should be simple. We adopt staff's recommendation that the payment for energy and capacity be expressed in terms of cents per kWh and be offered on either a time- or nontime-differentiated basis. In the context of this proceeding, this result is best achieved by a payment equal to the standard rate calculated for large QFs providing as-available energy as provided for above.

Our "as-available" offer for large facilities is on a time-differentiated basis, to reflect the fact that capacity is more valuable during peak periods than during other periods. In the event a qualifying facility less than 100 kW chooses not to buy a time-differentiated meter, the price incentive to be available during periods when capacity is most needed will be reduced. Consequently, utilities may propose capacity payments for qualifying facilities without time-of-use meters that aggregate over a year to 50% of the capacity for those with time-of-use meters.

Larger QFs will receive regular service from a utility under the applicable filed tariff schedule, standby service under a standby tariff, and parallel generation interconnection under either a parallel generation tariff or a standby tariff. Power will be purchased by the utility under a contract based on either the standard price offer or a negotiated pricing arrangement. For small QFs under 100 kW (and even for larger QFs if the utilities deem it feasible to do so), simplified service arrangements are necessary.

This should be accomplished by tariffs which cover services supplied by the utility, including parallel generation interconnection, and provide for simplified agreement forms.

These simplified tariffs will be based on the standard price offer and will not preclude small QFs from choosing options available under the standard price offer which may not be contained in the simplified tariffs. An example could be the option of simultaneous purchase and sale which would require additional metering and contract terms not provided for under the tariff offerings for small QFs.

The tariffs governing sales by QFs to utilities are in some respects conceptually different from usual tariffs which cover the terms and prices of services provided by the utility. Because of this difference, certain aspects of our General Order 96-A should not apply to the tariffs covering the QFs' sales to utilities (as opposed to tariffs setting forth the services provided by the utility to the QF and technical arrangements, such as interconnection requirements). First, any contracts authorized by these tariffs need not contain the contract provisions required in Section IX of General Order 96-A. Second, the provisions of Section X, concerning contracts and services at other than filed tariff schedules, should not apply to contracts differing from the terms of the simplified tariffs. The discussion of nonstandard contracts in the following pages also applies to deviations from the tariffs governing the QFs' sales to utilities.

D. Nonstandard Contracts

1. In General

We have provided for a "standard offer" that is intended to be widely applicable to QFs of diverse characteristics and to effectively promote cogeneration and small power production. The more generally suitable the standard offer, the less need for parties to negotiate nonstandard contracts.

Nevertheless, there remains the likelihood that nonstandard contracts will be necessary. The range of possible conditions that might lead to such contracts is too broad to support more than idle speculation. The object of negotiations is to produce a contract that is the economic equivalent of the standard offer.

We indicated above that payments under the standard offer are deemed reasonable and are recovered through ECAC. Payments pursuant to nonstandard contracts are recoverable through ECAC upon a showing of the reasonableness of such payments. This differing ratemaking treatment leads to one of the major issues in this proceeding - whether this Commission should devise a procedure for reviewing the reasonableness of nonstandard contracts in advance of their effectiveness. This issue is discussed below.

Another issue that concerns many parties is the prospect of protracted negotiations over contract terms. Several parties have proposed specific schedules for offers and replies, intended to alleviate this problem. This issue is also discussed below.

2. Advance Approval

Staff observes that uncertainties associated with nonstandard contracts might delay the development of cogeneration and small power production.

> "For example, utilities might hesitate to sign contracts containing price terms other than those approved in advance by the Commission, for fear that such price terms would be considered not 'sufficient to encourage cogeneration and small power production' (Section 292.304(b) (3)), or that payments made for power purchased under nonstandard contracts would not be fully recovered."

Although advance review by the Commission of nonstandard contracts might help to reduce uncertainty, staff rec-

ommends that the Commission not give advance review and approval. It recommends that review be limited to ECAC proceedings.

Staff warns that advance review might actually delay development, contrary to its intended purpose. The procedure might take months, with the prospect of a longer process if any party petitions for rehearing or petitions the Supreme Court for review. Any decision other than unconditional approval might require further negotiations, delaying the contract. The possibility of Commission review might cause the parties to rely less on their own bargaining skills and more on the judgment of the Commission.

Staff is uncertain regarding the exact nature of review anticipated.

> "If the Commission is reviewing executed contracts, such review would appear to be superfluous, because in that case the utility and the QF would have already freely agreed to a mutually satisfactory arrangement. Review for fairness to ratepayers would occur, as with other utility contracts for the purchase of energy or fuel, in the utility's general rate case or ECAC proceeding. If, on the other hand, the Commission is asked to review proposed contractual terms, the Commission runs the risk of inserting itself in the midst of contract negotiations or of becoming an arbitrator of the parties' differences. It would be inappropriate for the Commission to become an active participant in negotiations involving a utility which is subject to the Commission's regulation and a QF which is not directly under the Commission's jurisdiction and which has been specifically exempted from state regulation (§ 292.602(c))."

Staff is concerned that the QF would not want to disclose the information that would be necessary for effective arbitration.

Further, staff states that even the most cursory forms of advance review would require considerable time of the staff and Commission. Reviewing all nonstandard contracts, including those which vary only slightly from the standard offer, would be unnecessary and inefficient, but staff doubts whether effective guidelines could be devise that could distinguish between minor and major variations.

Staff observes that the purchasing utility does assume a risk by proceeding without prior Commission approval. It suggests that the Commission should clearly state that utilities are expected to assume some risk in contracting with QFs and urges that the Commission look favorably on a utility that willingly assumes such risk.

Staff recognizes the interest of many parties in having a procedure for advance review. It proposes such a procedure for comment though its recommendation is that no such procedure be adopted. The essence of its proposal is that either a utility or a QF may submit a "Request for Review" of a specific contract provision. The Commission may accept the matter for review, in which case, an application shall be filed. The Commission decision may be deemed precedential as regards similar provisions in similar contracts.

The utilities and many interested parties urge the Commission to undertake advance review. Both legal and policy arguments are offered in support of this position.

PG&E argues that Public Utilities (PU) Code Section 2821 requires the Commission to approve the payment terms of nonstandard contracts prospectively, referring to the following portion of the statute:

> "The Commission shall approve and establish equitable charges to be paid by an electrical cor-

> poration which purchases electricity from any private energy producer employing other than a conventional power source for the generation of electricity. . . ."

PG&E contends that the use of the words "to establish" and "to be paid" in the statute require that the Commission act prospectively. PG&E expects that as precedents are declared, only those contracts that deviate substantially from the standard offer or from those contracts previously reviewed will be submitted for review. PG&E predicts that review will be infrequent.

As a policy matter, PG&E argues that even if advance review is not required by statute, staff's proposal to deny advance review would deter QF development. Under such circumstances utilities will include a provision in all nonstandard contracts allowing the utility to adjust the contract to the terms and conditions subsequently approved by the Commission, and recover all payments in excess of those subsequently authorized. In such circumstances the QFs would have no certainty and the purpose of nonstandard contracts would be defeated.

PG&E is not persuaded by staff's warning that the review procedure might take months. PG&E argues that the time required of the Commission and the staff will not be conserved by postponing review until ECAC proceedings, since the same review is required before or after the effective date of the contract.

Edison contends that the Commission should review and approve or disapprove all nonstandard contracts between utilities and QFs prior to such contracts' becoming effective, whenever the price paid exceeds the utility's avoided cost.

> "In those rare instances where the overall benefits of a transaction, such as demonstrating a

> new technology, appear to justify the payment by a utility of a price in excess of its avoided cost, the Commission should review and either approve or disapprove the contract prior to its becoming effective. The Commission's review burden would be small under this approach because the utility will seldom wish to pay more than it can be compelled to pay. If the transaction appears to be truly beneficial, overall, the utility should not be subjected to second guessing by the Commission in a subsequent proceeding."

Edison suggests that there is no need for the Commission to review nonstandard contracts where the utility pays less than avoided costs.

Edison proposes that General Order 96-A, Section X should be amended. That section requires that no utility shall make any contract that deviates from its filed tariffs without Commission authorization. Edison suggests that amendment is required to remove uncertainty and ambiguity regarding whether that provision applies to purchases by a QF.

SDG&E believes that nonstandard contracts can perform an important function in promoting cogeneration and small power production. SDG&E warns that such contracts may at times exceed avoided costs and at times fall below avoided costs.

> "For this reason, the proposal made by Southern California Edison that only nonstandard contracts which exceed avoided costs should be subject to PUC approval is incomplete. SDG&E would suggest rather that the Commission only approve contracts upon which the QF and the utility have agreed but which they have not yet executed. The PUC's approval should be limited to the rate

> itself and the recoverability of that rate by the utility."

SDG&E foresees that eventually there will develop "a uniform nonstandard contract rate which many parties could utilize."

SDG&E contends that policy and legal considerations require advance approval. Regarding policy, it states that staff misunderstands the character of purchased power contracts that are not subject to Commission approval:

> "Since the majority of such purchased power contracts has (sic) already been determined by the FERC to be reasonable, the utilities are not nearly as vulnerable to an adverse PUC determination as Staff would suggest. Most purchased power contracts are not like ordinary commercial agreements in that regard."

SDG&E points to its Heber Binary Project and the Magma Niland Geothermal purchased power contract as examples of prior approval entertained by this Commission.

SDG&E argues that the Commission should provide for advance review as a matter of simple fairness, referring to the prospect of a rate of return penalty if the terms of its contract are not sufficiently fair to the QF, or having expenses disallowed in an ECAC proceeding if the payments are too high.

SDG&E makes the same legal argument advanced by PG&E - that PU Code Section 2821 requires advance approval. SDG&E contends that while this proceeding may constitute sufficient review of utility standard offers, it is clearly not sufficient for nonstandard contracts "since these contracts are not the subject matter of this proceeding." SDG&E suggests that staff's concern that the Commission might end up in the role of an arbitrator is resolved "by simply requiring that the parties agree in the first place

as to the terms of the contract before it is submitted to the PUC for approval."

SDG&E concludes that "if the PUC will not grant prior approval to the nonstandard contracts, the utility must protect itself in some form." SDG&E anticipates that it would react similarly to the manner described by PG&E - inserting into the contract a provision that payments are subject to modification upon an adverse determination by this Commission and that overpayments would be recovered from the QF. The resulting uncertainty would discourage QF development. SDG&E urges this Commission to reaffirm its commitment to cogeneration by approving a procedure for prior approval of nonstandard contracts.

CEC supports the utility position. It contends that prior review will be essential to QF financing efforts.

> "This conclusion is based upon a clause which each of the utilities have placed in their contracts, which states in effect, that the contracts shall not be effective until the Commission has approved each and every term and condition of the contract. The net effect of this kind of clause is to mandate renegotiation of the contract should the Public Utilities Commission say no to any term or condition."

Union asserts that PURPA and the FERC regulations were intended to eliminate this regulatory barrier and to allow industry to negotiate freely with utilities. Union contends:

> "Prior review would not only carry the onus of regulation where none is warranted, it would also be time-consuming and costly. It would tend to discourage rather than encourage industry seeking contracts to sell power. In addition, it would require direct intervention of the Commission in what would ordinarily be private negotiations be-

> tween two (or more) business interests. This would have the appearance as well as the indirect effect of, further regulation, even apart from the ECAC and general rate proceedings."

Union goes so far as to suggest that review and approval of contracts by the Commission and the indirect terms and conditions of these contracts through the device of after-the-fact refusal to allow recovery of costs in ECAC or general rate cases is an unwarranted inhibition to the further development of cogeneration.

Pan Aero and Transition Energy Projects Institute (TEPI) also oppose advance review. TEPI suggests that if advance review is adopted, that only concluded contracts be submitted unless there are irreconcilable differences requiring Commission review.

Discussion

The threshold question is the legal question. After consideration of the authorities cited, we conclude that we are not legally compelled to provide for advance review of nonstandard contracts.

As indicated, several parties argue that advance review is required by PU Code Section 2821. We find this argument without legal merit.

PU Code Section 2821 does provide that this Commission "shall approve and establish equitable charges . . . on its own motion or on application of an electrical corporation or a private energy producer." We consider this mandate to be no more than a direction that we provide for a "standard offer". We conclude that by this decision we are acting on our own motion to "approve and establish equitable changes." We find no additional burden to entertain applications on behalf of parties that are not satisfied with the "equitable charges" established by this Commission.

We also seriously doubt whether PU Code Section 2821 would provide the procedural vehicle intended by the par-

ties. In general, these parties seem to have in mind a procedure whereby an executed contract is proffered for approval or disapproval. But if we assert jurisdiction under PU Code Section 2821, our authority would be to "approve and *establish*" charges to be paid under a nonstandard contract. Thus, we would have jurisdiction to substitute our own judgment and to modify the contract accordingly. This is certainly not the process intended by the parties.

We are also not persuaded that General Order 96-A has any relevance to this issue, except as an argument by analogy. On its face it applies to utility sales to customers, not to utility purchases that may be from customers.

While we do not find ourselves legally obligated to provide advance review of nonstandard contracts, we have decided to provide such review for applications filed during the next two years. Both utilities and QFs argue that advance review of nonstandard contracts may in some cases be necessary. We are persuaded that without advance approvals, creative nonstandard offers could be stymied and that QF development would thereby suffer.

The nonstandard contracts we anticipate generally involve some sort of debt guarantee, levelized payment or payment floor which reduces risks for QFs and places those risks upon ratepayers. In return for taking such risks, ratepayers are afforded some reduction on avoided cost payments. Given current ratemaking treatment for costs associated with QF purchases, utilities are intermediaries in the transaction as costs are flowed through ECAC. In the case of standard offers, utilities are secure that payments to QFs will be recovered. With *nonstandard* offers, the utility has no such assurance unless advance review is permitted. Without advance review, a utility risks being found imprudent for nonstandard contract payments; a potential cost for which the utility has no compensatory benefit. Under the circumstances, a utility is likely to choose not to write nonstandard contracts at all, or to include in

such contracts a provision to void the agreement if an associated expense is disallowed by this Commission, or to demand such concessions from QFs beyond the standard avoided cost offer that QFs are discouraged from departing from standard offers at all.

The issue, then, is whether we wish such nonstandard contracts to be written. It is not necessarily clear that we do. In adopting standard offers, we are presenting our conclusion on what is an appropriate payment for electricity provided by a QF. We believe our standard offer is a fair price for ratepayers, and provides an excellent opportunity for QFs to prosper. We would expect most parties to find such an offer satisfactory, and that special financing or other measures to reduce risk be sought from financial or other institutions.

While we believe that the standard offer should be satisfactory generally, we can envision some cases in which nonstandard treatment would benefit both the QF and ratepayers. Especially as the QF market is developing, and before financial and other institutions understand its nature, some QFs may wish to seek alternatives to reduce risk. For example, the agreement SDG&E recently reached with Kelco to provide a floor on avoided cost in return for a reduction in payment appears to be desirable to all parties, including ratepayers. We can imagine other such contracts which benefit ratepayers. We will entertain such applications within the guidelines established.

The guiding principle for nonstandard contracts upon which publications should be based is that the contract terms, taking into account the associated risks, should not be more than expected avoided costs under the standard offer. Ratepayers are expected in most non-standard offers to accept some technological or market risk, in which ratepayers should be returned compensating benefit. Applications for nonstandard contacts should clearly state all the differences between the contract and the standard of-

fer, and identify all gains and costs for ratepayers. The application should further demonstrate why ratepayers should either be indifferent to or prefer the nonstandard contract over the standard contract. In the rare event that the nonstandard offer is above avoided costs an explanation of how ratepayers otherwise benefit should be presented. In all cases, the burden is on the applicant to demonstrate why the nonstandard offer is in the ratepayers' interest. We must caution all parties that the Commission will review these contract as a banker reviews a loan application, with scrutiny and skepticism. While we want to encourage QF development, we do not wish to burden ratepayers in the process.

In terms of procedure, we will allow utilities to file nonstandard offers for review. We ask that utilities submit only those offers for which the utility has significant questions about whether we would find the offer prudent. Once the Commission has reviewed and expressed its opinion as to the consistency of a contract price and terms with avoided cost principles, utilities should be expected to use these principles to sign similar contracts without review. We will attempt to handle applications for projects less than 10 MW through ex parte procedures. Applications over 10 MW will generally require hearings. Exceptions may be made depending upon the novelty of a particular application, or the degree of ratepayers' exposure.

The staff shall review applications for approval of nonstandard contracts expeditiously and where hearings are necessary, they shall be set promptly. If the staff finds that staff review cannot be completed and hearings begun within 45 days because of the workload of other matters pending before the Commission, the Executive Director shall report this to the commission, which may then reorder work priorities to resolve related issues promptly.

Our staff makes strong arguments in this proceeding against advance approval. It argues advance approval could

lead to delay of projects, and to direct involvement of this Commission in the negotiations with QFs. On the first point, we acknowledge that review of contracts may be time-consuming. It is for this reason that we ask that QFs generally seek financial support through other institutions, not through nonstandard offers. At least while the market is developing, however, we see merit in permitting some nonstandard contracts even though such review will be time-consuming. We would prefer to have good projects somewhat delayed than not constructed at all.

Finally, on the issue of PUC involvement in negotiating nonstandard offers, we do not believe it will be necessary or appropriate to become involved. Utilities and QFs are to negotiate with each other, and we will review the product for approval or disapproval. We have no intention of intervening or rewriting contracts.

To assure review of this procedure after we have had experience with it, we will establish a sunset provision. Unless we make an affirmative decision to reinstate our procedure, we will not consider applications for prior approval of nonstandard contracts filed two years after the effective date of this decision.

3. Negotiations

Staff states the obvious: "Utilities are expected to negotiate in good faith with QFs." Staff proposes certain guidelines that are intended to provide a standard:

> "A utility must respond specifically to proposals of a QF within 60 days of the receipt of the QF's initial contract proposal and within 30 days of the receipt of subsequent proposals related to the initial proposal. Rejection of a QF's proposal shall be accompanied by a specific counter-offer concerning the subject matter of the QF's proposal. If the utility is unable to respond to the QF's proposal within 30 days, it shall inform the QF of

(1) the specific information needed to evaluate the proposal, (2) the precise difficulty encountered in evaluating the proposal, and (3) the estimated date when it will respond to the proposal."

Other parties respond with schedules of their own.

We are not sure that the give and take of contract negotiations can be reduced to a formal schedule. We are not inclined to require such a procedure without a more convincing argument that it is necessary, or likely to be successful. Enforcement would require the parties to conduct their affairs in an overly rigid fashion. For example, the QF's "initial contract proposal" might evolve, rather than simply appear. We would rather not have to decide which was the day the proposal was complete, or whether the utility's estimated time for response is reasonable.

Nevertheless, we recognize that staff has addressed an important problem. Protracted negotiations that lead nowhere are exactly what this regulatory scheme is intended to avoid. The utilities are expected and shall be required to bargain conscientiously toward a conclusion. The best evidence of good faith is a collection of written documentation compiled along the way. When the utility is unwilling or unable to accept a QF's proposal, the utility must respond with a timely counteroffer, or an explanation (as proposed by the staff) of:

1. The specific information needed to evaluate the proposal;

2. The precise difficulty encountered in evaluating the proposal; and

3. The estimated date when it will respond to the proposal.

The Commission will entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. Such complaints from QF's shall be

treated expeditiously by the staff, and where hearings are necessary, hearings shall be set promptly. If the staff believes that QF complaints cannot be resolved quickly because of the workload of other matters pending before the Commission, the Executive Director shall report this to the Commission so that the Commission can assign priorities to these matters and resolve the QF complaints as quickly as possible. A utility found not to have bargained in good faith will stand in violation of this order and will be open to potential punitive action by this Commission.

We are also concerned that QFs considering a negotiated contract are not fully aware of their rights to request a contract under the terms of the standard price offer. Should the QF propose prices or terms outside the standard price offer, we will expect the utility to advise the QF that the contract discussions are proceeding on a negotiated basis, distinct from the standard contract, before responding with a nonstandard contract. The notice shall include a summary of terms available under the standard offer, and an offer to enter into a standard offer contract. Likewise, if the utility initiates a nonstandard contract with its attendant price offering, the utility will be expected at the same time to present to the QF the standard offer.

4. Contract Renegotiation Provision

We are concerned about the utility-proposed renegotiation contract term which would allow the utility to modify a signed contract retroactively (and prospectively) in the event any provision is found unreasonable in the future. Such a term would apparently destroy the certainty that financial institutions require for their participation. We find that such a term should not appear in standard offers. A contract term which would allow the utility to modify a signed contract retroactively and prospectively in the event any provision of the contract term is later found unreasonable is not a reasonable term in a standard offer contract.

V. Wheeling

FERC regulation Section 292.306(d) provides for limited wheeling:

> "If a qualifying facility agrees, and electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e) (4) and shall not include any charges for transmission."

In its comments FERC indicates that there are several circumstances in which a QF might prefer that an electric utility with which the purchasing utility is interconnected would make such a purchase - for example, if the avoided costs of the second utility are higher. However, if the first utility does not agree to transmit the purchased energy or capacity, it is not forced to wheel and retains the purchase obligation.

Staff states that the extent of state authority to order wheeling is limited by federal law by virtue of the preemption doctrine. It points to PU Code Sections 2801-2816 as providing this Commission with limited jurisdiction to order interconnection for the purpose of transmitting energy on behalf of a "private energy producer," assuming that certain specified findings are made. Staff argues that these sections avoid federal preemption because jurisdiction is limited to transmission for the private energy producer's own use and because the transmission is limited to the service area of a single utility. Staff concludes that, although the Commission

has no authority to require wheeling when federal jurisdiction attaches, utilities should be urged to consider wheeling requests on a case-by-case basis.

The utility response is varied. PG&E states that staff's position agrees with its view. Edison argues that even transmission on behalf of a private energy producer is subject to exclusive federal jurisdiction through application of the commingling doctrine. SDG&E focuses on conditions that it proposes to require in the event that QF generation is made available by a wheeling utility.

CEC contends that this Commission should state clearly that utilities are encouraged to wheel. It states that this Commission can and should use our authority to ensure that utilities do not use their monopoly control over transmission lines to hinder QF production. It offers the following statement for our endorsement:

> "The Commission will not tolerate the utilities' use of their control over the transmission system to limit access by small power producers who seek to use the transmission lines to transmit power to a purchaser of the small power producers' energy. Such actions will be considered by the Commission in setting rates for utilities in future ratemaking proceedings, and in evaluating the utilities' imagination and vigor in implementing and pursuing conservation and the development of small power production and renewables."

CEC suggests each utility report regarding requests for transmission service as part of its rate case showing.

Union states that wheeling can be a major factor in promoting cogeneration and small power production. It urges this Commission to strongly encourage utilities to consider all requests to transmit power and to accommodate such requests on a fair and nondiscriminatory ba-

sis. It warns that otherwise even such large companies as Union may be discouraged from pursuing opportunities.

NRDC argues that staff's conclusion regarding the extent of our jurisdiction is based on an unnecessarily narrow view of wheeling issues. It recommends that we consider fashioning "narrowly tailored wheeling requirements to further the objectives of PURPA."

CMA addresses specifically the issue of wheeling between two facilities of the same industrial entity. It argues that the principle of simultaneous purchase and sale fundamentally changes the concept of wheeling. It contends that the principle applies whether the resources and load are on the same site or separate sites. CMA observes that the utilities readily accept the same site principle, but reject its extension to separate sites.

We agree that wheeling is an important concept that can make a material contribution to cogeneration and small power production in California. For that reason we state plainly that each utility's willingness to wheel will be examined in the context of its overall conservation activities in conjunction with general rate case proceedings.

Regardless of a utility's willingness to wheel power for its neighbor, each utility, for some reason, appears to limit its cogeneration and small power activities to the confines of its own service territory. This occurs even though locally available generation may not match requirements. Further, some generating sites, while located in other service territories, may still be closer to the buying utility's load center than would alternatives such as out-of-state power purchases. We find that it is not prudent for a utility to fail to pursue an otherwise beneficial facility simply because it is located in another service territory. In addition, this Commission will view with disfavor any actions or inactions by a utility which will interfere with the signing of a contract between a neighboring utility and a cogenerator or small power producer located in its service territory.

In the discussion above we considered whether to limit utility recovery in cases of utility participation in successful cogeneration and small power production ventures. We indicated that such participation should be favored. In relation to wheeling this principle applies to the prospect that a major facility may require utility financing or guarantees in order to be built (a classic "nonstandard" contract) that the "host" utility is unwilling or unable to provide (for example, the utility may already have excess capacity). In this case another utility may be able to participate under terms and conditions that benefit all parties.

The attractive feature of wheeling is that it introduces actual competition into the market. To the extent that competition occurs, the burden of regulation is proportionately reduced.

Respondent utilities are required to buy energy and capacity from a QF located in the service area of another utility whenever the conditions of Subsection 292.303(d) of the FERC rules are met.

Subsection 292.303(d) is clear that the price paid to the QF by the purchasing utility shall not include any charge for transmission but may be either raised or lowered to reflect the savings or costs resulting from line losses. The discussion accompanying the final FERC rules indicates that the serving utility would collect any applicable transmission charges for wheeling power from the QF and that, in the case of respondent utilities, the rates for these charges would be set under Part II of the Federal Power Act. Transmission charges by the serving utility should take into consideration the extent to which the QF's power displaces power that would otherwise be transmitted from the utility which receives the QF's power to the serving utility. For example, if all of the QF's power displaces power that would otherwise be delivered by the purchasing utility to the serving utility, the transaction becomes a

bookkeeping rather than a physical exchange, and therefore no transmission charges would appear to be justified.

At this stage of this proceeding we are optimistic that the respondent utilities subject to this Commission's jurisdiction will respond to wheeling requests in a fair and nondiscriminatory manner. If our optimism is well-founded, we will need not decide the extent of action needed to encourage wheeling. If our optimism is unfounded, we will take what ever action is appropriate.

In this posture we must necessarily require information to be provided periodically regarding utility actions in this regard. Therefore, we will require each utility to report at the end of January of each year on wheeling performed during the previous year, the parties for whom the wheeling was performed, the terms and conditions applied to the transaction, the technical wheeling arrangements, the status of any pending requests to wheel, and the circumstances relating to any request that was refused.

VI. Rates for Sales to QFs

A. Introduction

FERC Regulation Section 292.305 provides that rates for sales to QFs shall be just and reasonable, in the public interest, and shall not discriminate against any QF in comparison to rates for sales to other customers served by the electric utility. Rates based on accurate data and consistent systemwide costing principles are deemed not to discriminate, to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics. Upon request of a QF, each utility must provide:

1. Supplementary power,
2. Backup power,
3. Maintenance power, and
4. Interruptible power.

The appropriate state regulatory agency may waive the requirements upon a finding that compliance would impair the utility's ability to render adequate service to its customers, or place an undue burden on the utility. The regulation expressly provides that the rate for sales of backup or maintenance power should not be based upon an assumption that forced outages or other reductions in output will occur simultaneously, or during system peaks, or both, and shall take into account the extent to which scheduled outages of the QF can be usefully coordinated with the utility's own scheduled outages.

B. Supplementary Power

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. The concept is not applicable when simultaneous purchase and sale is elected, as the QF is supplied all of its requirements by the serving utility.

Staff states that QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF. Staff contends that such service does not involve costs that differ from costs to serve other customers. It finds that present practice reasonable and recommends that it continue. No party objects to this recommendation.

C. Backup Power

Backup power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff argues that there is a significant cost to a utility to provide backup power to a QF that is not recovered through energy rates charged for supplementary power and not reflected in avoided cost payments. Staff contends

that reasonable standby rates, based on the utility's cost of providing backup power, should be charged to QFs.

Staff states that:

> "Standby rates as now filed by PG&E, SCE and SDG&E are designed to recover the utility's cost of providing only a fraction of a MW of backup generation costs together with transmission and distribution costs. . . . Standby rates, by themselves, do not recover the utility's cost of providing backup power. The rates were set so that the standby charges combined with the recovery of demand charges through regularly filed tariffs in those months in which the QF requires backup power would recover the utility's costs."

Staff asserts these rates are consistent with the FERC requirement that such rates not be based on the assumption that all QFs will fail simultaneously. Staff recommends that this Commission not adopt a formula for developing standby rates. Existing rates are allegedly below rates that would result from such a formula. Staff suggests that the Commission accept existing basic standby rate levels in dollars per kW per month as reasonable and allow rates to increase in general rate cases in proportion to increases in per kW capacity costs.

Staff recommends no standby rates for QFs not now served by rate schedules with demand schedules. Standby rates for new technologies such as photovoltaics should not be finalized at this time. Appropriate rates could be developed as data on the technology becomes more refined.

Staff recommends that all utilities develop and file alternative standby rates for QFs on time-of-use rates. These rates should be similar to Schedule SCG-2 of Edison. A three-month ratchet, including the month of occurrence, is recommended. The ratchet would not exceed 90% of the demand in the month of occurrence and would be extended

by three more months for each additional occurrence, but not to exceed 12 months. Staff recommends that PG&E, with no ratchet provision in its present time-of-use tariffs, should develop and propose an appropriate alternative standby rate.

Staff further recommends that standby charges should be waived for any QF that attains an 85% capacity factor without downtime during on-peak periods, excluding scheduled maintenance, in any month. This waiver is in recognition of the lower cost to serve QFs that operate with high reliability.

Staff also proposes that standby rates be made available to self-generators used to reduce peak demand. Staff states that such rates are appropriately higher than rates to QFs, "in recognition of the lesser value of self-generation to the utility." Self-generators reduce the utility's peak demand but do not conserve energy through enhanced efficiency or fossil fuels as compared to a cogeneration or small power production facility.

PG&E does not have a ratchet provision in its present time-of-use tariffs. PG&E opposes staff's proposal that it develop such provisions as part of "an appropriate alternative standby rate." It states that its present schedule offers low standby rates to both large and small cogenerators.

> "This schedule does not burden a QF with disproportionately higher standby charges if the size of the cogeneration facility is larger than 40 percent of the load."

PG&E asks to be excused from filing the proposed rate.

PG&E disagrees with staff's proposed waiver of standby costs where the QF attains an 85% capacity factor in any particular month. PG&E claims that attempts to comply would be difficult because a utility does not ordinarily meter cogeneration production and would have no basis for ac-

curately computing the capacity factor. Installation of the additional meters would increase the cost of interconnection.

PG&E also disagrees with staff's alternative recommendation. PG&E agrees that no generation costs, except for spinning reserve, are incurred in providing standby service outside of peak hours. However, it contends that portions of the transmission and distribution system are dedicated to serve certain customers and that such costs are reasonably reflected in rates.

Edison objects to staff's proposed three-month ratchet provision. Edison claims that the 12-month ratchet is appropriate because the monthly standby charges are designed to recover 1/12th of the annual costs that Edison incurs in providing standby service. If the ratchet is reduced to three months, a higher charge would have to be imposed to recover the "full cost" of providing standby service.

Edison also opposes staff's proposed waiver of standby charges where the QF attains an 85% capacity factor in any particular month. Edison warns that such a provision would tend to eliminate standby charges altogether, since standby charges are already waived if the customer generation suffers an outage (and Edison supplies the demand) on-peak.

SDG&E agrees that existing ratchet provisions are reasonably modified to encourage reliable customer generation. It suggests that this might be done by extending the time effect of the ratchet and increasing the ratchet level for repeated outages.

SDG&E does have reservations about staff's proposed waiver of standby charges based upon performance. If staff's proposed waiver of demand charges during scheduled maintenance (discussed below) is also adopted, SDG&E contends that "the combination of the two waivers would mean that the QF pays neither a standby charge for demand nor a

demand charge when it actually imposes demand during scheduled maintenance." This is alleged to discriminate against retail customers who do pay for demand.

CMA states that demand ratchets and demand charges for generation, transmission, and distribution are not appropriate. Electricity used by the QF should be charged at the utility's marginal running cost. However, CMA agrees that standby schedules such as developed by Edison are an acceptable alternative for balancing FERC's intent with the purpose of standby schedules by reflecting significant differences in cost between periods.

The University of California (UC) prefers staff's alternative approach to standby rates. UC contends that, considering all QFs as a class and the diversification of probable QF outages, the inclusion of capacity or demand charges/payments in rates should operate to provide for any standby capacity requirements.

Solar Turbines International (Solar) supports the staff recommendation with regard to self-generators. Solar argues that SDG&E's existing ratchet-type standby charge operates inequitably in favor of generators who are generating a small percentage of their total requirements.

> "The cogenerators who are generating a large percentage of their capacity would opt for the flat charge rate, and the cogenerators and self-generators who are generating a small percentage of their power would opt for the ratchet clause, which means that the only generators which would be penalized by this ratchet clause would be the self-generators who are generating a large percentage of their power."

Solar recognizes that self-generators do not effectuate all of the objectives of PURPA. However, it contends that they do accomplish some of these as well as do cogenerators, and asks for appropriate treatment.

CEC recommends that rates be established without standby rates and that service be provided under conditions in tariff schedules. CEC states that under standby rates, the QF pays for its own reserve margin, but receives no benefit from its contribution to reduced reserve requirements. CEC suggests that certain distribution costs required to provide standby service can instead be recovered through facilities charges.

We find that the utility position is consistent with the increase in supply approach discussed in relation with capacity payments above. The CEC position is more consistent with the reduction in demand approach, as it recognizes the central proposition that the proliferation of cogeneration and small power production enhances reliability in the aggregate. However, we do not yet reach the conclusion drawn by CEC - that no standby rates should be charged.

Instead, we consider that standby rates are properly derived residually, based on the calculation of avoided costs and the determination of retail rates.

We earlier stated the proposition that standby rates do not apply when simultaneous purchase and sale is elected. In that case, the economics of the transaction are a function of two variables - the avoided costs and the retail rates. Simultaneous purchase and sale is a fiction - from the point of view of the utility, the operation of the system is exactly the same whether or not simultaneous purchase and sale is elected. We can think of no reason why the standby rate should be a major factor in a QF's decision whether to elect simultaneous purchase and sale. Therefore, the standby rate should be designed so that the total economic package is the same for a QF facing the election.

The present utility standby rates, which have been developed after much discussion and analysis, provide a good basis to achieve this balance. Standby rates apply to the QF that is serving its own load and requires backup power

for periods when its generation is down. If the QF is suffering an unscheduled outage, it pays the regular tariff rates for power purchased from the utility, which include a demand charge for that month. These rates when taken together provide for a reasonable recovery of backup utility generating costs when requisite consideration is taken of the noncoincidence of QF failure.

We will extend standby rates to all QFs, not just cogenerators, with demand schedules. We agree that these rates should be updated in general rate cases in proportion to increases in per kW capacity costs. We will also adopt the staff recommendations which provide for some options that should cover the diverse needs of different types of QFs. Currently, under certain utility price offers QFs must maintain 80% availability on-peak to receive firm capacity payments. The elimination of standby charges for QFs who attain an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times. Alternative standby rates should be promulgated for QFs on time-of-use rates to distinguish between the impact on the utility system of QF failure on-peak as opposed to off-peak. Failure on-peak imposes an incremental demand on the utility that is properly reflected in a demand payment, as in Edison's Schedule SCG-2. Failure off-peak imposes no such system demand problem. We adopt the staff's three-month ratchet proposal, as part of this rate scheme. This option should be appropriate for a QF with small generation output compared to its total demand. PG&E will be ordered to adopt a standby rate proposal consistent with these provisions.

D. Maintenance Power

Maintenance power is electric energy or capacity supplied during scheduled outages of the QF. By prearrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during

peak periods. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff states that PG&E now provides maintenance power to QFs under a special condition whereby customers are charged for energy furnished during scheduled maintenance under the regular rate schedule applicable to that customer. Added demand imposed on the utility by the scheduled outage is ignored for the purpose of computing demand charges under the regular rate schedule.

Staff recommends that QFs pay for energy delivered by the serving utility at regular rates during periods when their own generating unit is shut down. Staff proposes that PG&E's special condition (Special Condition 2 of Schedule S-1) be adopted by other utilities to provide for the waiver of added demand charges during scheduled maintenance periods. In adopting this provision, other utilities may take into consideration differences as to months that are appropriate to that utility for scheduling maintenance consistent with system peak loads. In establishing schedule maintenance periods, the utility will state that reasonable periods will be allowed and that deferrals of QF's requested schedule will be made on not less than 60 days' notice.

As an alternative, staff suggests that maintenance power rates be set at the utility's marginal cost:

> "The argument for charging the utility's marginal (avoided) cost is to keep the utility whole. Tariffs are now set considering, but not equal to, the marginal cost. When a QF uses maintenance power, the utility by definition suffers its marginal cost (change in total cost for a charge in output). The utility will lose money on maintenance power to the extent filed tariff rates are used and they are below the marginal (avoided) cost. Conversely, the utility will earn revenues above their expenses on maintenance power when

filed tariffs are used and they are above the marginal (avoided) cost."

In this case the rate charged is the same as the price the QF would otherwise receive as payment if it were delivering power (assuming it is paid based on current avoided costs).

Staff in its alternate further suggests that demand charge ratchets should not apply for maintenance power if the QF cannot schedule maintenance in the few months offered by the utility. Demand charges should apply for the month in which power is used, but should not be carried forward for the next 11 months.

SDG&E opposes the waiver of demand charges incurred for additional demand during scheduled maintenance periods. SDG&E states that while current schedules do waive any ratchet penalty for demands imposed during scheduled maintenance periods, all portions of retail rate schedules are appropriate to charge for power used. To eliminate any portion of the retail charge could be viewed as discriminating in favor of QFs.

SDG&E disagrees with the concept of dropping the ratchet penalty for unscheduled outages or outages scheduled without the concurrence of the utility. SDG&E views QFs as alternatives to utility generation and considers the ratchet provision a reasonable means of ensuring that the QF will build reliable units and schedule maintenance to avoid periods of high demand.

CMA states that if maintenance is performed during the scheduled period, no demand is imposed and demand charge is inappropriate. Limited (three months) ratchets may be appropriate for QF on-peak demand resulting from unscheduled breakdown. The shorter ratchet is proper recognition of the fact that requirements for maintenance power will not be simultaneous.

We find that this issue is properly addressed relative to the standard offer choices discussed above. The QF that chooses to provide as-available energy and associated capacity is under no obligation to schedule maintenance consistently with utility load requirements. Since payments to the QF are based on the utility's avoided costs, such a QF that is "out" during peak periods forgoes payments at the most lucrative time. As retail rates evolve toward marginal costs, such a QF also pays higher rates at such times by application of the retail rate schedule. We rely on such price signals to promote efficient operation of such facilities. We note that the higher the capacity payment at peak, the greater the incentive to schedule maintenance for off-peak periods. This relationship supports our conclusion that QFs providing as-available energy should be paid for capacity.

Those QFs that contract to provide firm energy are properly subject to the utility's scheduling requirements. We find the timing provisions set forth in PG&E's Special Condition 2 to Schedule S-1 to provide a reasonable standard for scheduling. The value of this commitment is correctly reflected in a higher capacity payment, as greater costs are avoided. Power during scheduled maintenance periods should be provided to the QF at the regular tariff rate. Added demand charges are appropriately waived for those QFs who are able to meet utility schedules. However, some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the seasonal nature of such QFs' operations. In such special cases, the demand ratchet triggered by this added demand should be limited to three months, with the exception that a three-month ratchet (three months including the month of occurrence) should apply for the first outage and three more months added for each additional outage (up to the present 12 months). PP&L, Sierra, and CPN shall be ordered to file rates consistent with this section.

E. Interruptible Power

Interruptible power is electric energy or capacity supplied to a QF subject to interruption by the electric utility under specified conditions. Many utilities have used interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than noninterruptible service.

Staff observes that Edison and SDG&E presently offer standby rates based on interruptible service. Such rates are available to large customers with loads greater than 1,000 kW who are on time-of-use rate schedules. Staff states that PG&E does not have an interruptible rate compatible with cogeneration by QFs. Staff suggests that PG&E be directed to file such rates.

Staff states that implementation of interruptible rates requires a phasing in, starting with large customers. Staff warns that interruptible service to smaller customers may cost more than the benefits are worth. Staff claims that more experience is needed with experimental offerings before such rates can be offered to smaller customers. However, utilities are required under PURPA to offer interruptible rates to all QFs unless a waiver is granted by this Commission.

PG&E agrees with staff. SDG&E states that:

> "The problem with expanding Interruptible Standby is the practical one of how does one interrupt the standby service without interrupting any remaining firm service. If the QF is willing to accept total service interruption or some positive measure can be taken to interrupt only the standby portion of the service, SDG&E has no objection to expanding Interruptible Standby."

SDG&E agrees with staff that interruptible rates may not be cost-effective for small customers.

The interruptible rate concept is applicable to QFs to the extent that QF's generation is used to serve its own load. We consider the FERC reference to "lower rate than noninterruptible service" as limited to customers of the same class, not that the interruptible rate must be lower than any noninterruptible rate. We recognize that interruption can provide both capacity and energy savings, and conclude that the actual rates should be based on the benefits that result from the avoided cost calculation and prevailing retail rates so that the appropriate price signal is available to the QFs.

As recommended by the staff, Edison and SDG&E should expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum and PG&E should offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers. PP&L, Sierra, and CP National should state their willingness to provide interruptible service to large QFs on a contractual basis. Interruptible rates for smaller QFs will be explored when more information is obtained on the costs and benefits of such offerings. Offerings to smaller QFs should occur at the same time that similar interruptible rate offerings are made to classes of customers below 500 kW.

VII. Standards for Safety

A. Introduction

FERC Regulation Section 292.308 provides that the appropriate state regulatory agency may establish reasonable standards to ensure system safety and reliability of interconnected operations. Standards may be recommended by any electric utility, QF, or other party. If standards are established, the state regulatory agency shall specify the need for such standards on the basis of system safety and reliability.

FERC's comments in regard to this section indicate that FERC:

> ". . .believes that the reliability of qualifying facilities can be accounted for through price: namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.
>
> "As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity."

Instead, the focus is on safety equipment that can ensure that QFs do not energize utility lines during utility outages.

Our staff states as a basic objective that "reasonable uniform standards should be established and be part of each utility's new parallel generation tariffs." This matter is related to the problem of interconnection, discussed in the following section of this decision. The solution of these technical problems is crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of the energy and capacity.

B. Staff Recommendation

Staff observes that various abnormal conditions can occur on a utility system. Some of these conditions will require detection devices and proper operation of protective equipment to prevent a hazard to the public or utility linesmen. For example, downed utility lines could pose a hazard to the public if a QF's generator continued to energize the line. Protective equipment must be provided to detect this condition and disconnect the QF's generator from the downed circuit.

Staff states that the QF should assist the utility in maintaining system integrity. For example, the QF's relays

should not frequently trip so that the QF cannot be relied upon to carry its share of the load. System disturbances also could result from inadvertent tripping of large QF generators. Staff proposes that utilities present adequate examples of how their guidelines deal with maintaining service standards and system integrity so that the QF is told clearly and simply not only what type of equipment is needed, but also the reasons the equipment is needed and what the equipment is expected to do.

Staff has identified three functional standards that it considers essential for safe and reliable operation, with a list of corollary conditions. The standards are as follows:

1. Sense and properly react to utility failures/ malfunctions;
2. Assist the utility in maintaining system integrity and reliability; and
3. Protect the safety of the public and utility personnel.

The corollary conditions are that the QF provide protection against the following adverse conditions, which can cause electric service degradation, equipment damage, and harm to others:

1. Prevention of inadvertent and unwanted re-energization of a utility dead line or bus;
2. Interconnection while out of synchronization;
3. Overcurrent;
4. Utility system load imbalance;
5. Ground faults;
6. Generated ac frequency outside permitted safe limits;
7. Voltage generated outside permitted limits; and

8. Poor power factor.

Staff suggests that QFs of 100 kW and larger may also be required to have overcurrent protection, utility system load imbalance protection, and a suitable power factor or power factor compensation up to nameplate generation capacity.

Regarding the respective responsibilities of QFs and serving utilities regarding design, installation, operation, and ownership of interconnection equipment, staff believes that the QF should be required to protect its own equipment in such a manner that faults or other disturbances on the utility system do not cause damage to the QF's equipment. Further, staff proposes that the QF take certain responsibility for protecting the public and utility operating personnel. Staff provides that the QF "may employ industrial quality interconnection equipment" for this purpose, with design review by the utility.

Except for the utility manual disconnect and feeder reclose blocking equipment, staff proposes that the QF have the option of owning, operating, and maintaining the interconnection protective equipment, or paying the utility. The utility must complete design review within a specified period and respond in writing, either accepting the QF's plans or providing detailed information regarding deficiencies.

Staff states that progress is being made in arriving at fairly uniform interconnection requirements. It asks that each of the utilities provide illustrations of how its requirements would apply to certain specified situations. Staff proposes that each utility complete its guidelines based on staff's recommendations in this matter.

Staff classifies three sizes of generating facilities: small - below 100 kW; medium - 100 kW to 1 MW; and large. Staff recommends that utilities review their requirements for small size facilities with the objective of simpler re-

quirements and standardization. Dedicated transformer requirements should be limited to not greater than 1.15 times the QF's generator nameplate capacity. Daily logs of generator trips and separations for small QFs shall not be required. Staff suggests that utilities establish requirements for the medium-sized facilities that are simpler than for the larger size. For all sizes staff suggests that utilities include diagrammatic examples of interconnection arrangements in their guidelines.

Staff state that utilities now require a voltage and frequency window-type of control for induction generators and other utility line-commutated generating devices, to assure such devices will trip off the line and stay off in an emergency. Staff contends that this practice is the lowest cost control method capable of performing well, and staff recommends its continued use. However, staff suggests that utilities examine other means of safeguarding the public and operating personnel, while assuring system reliability.

Staff proposes that these principles be incorporated in parallel generation tariffs to be filed by each utility under General Order 96-A, with modifications to be reviewed before becoming effective to protect QFs from arbitrary changes.

Staff states that an alternative and more time-consuming procedure would be for this Commission to issue detailed interconnection regulations in the form of a general order. Staff recommends that such action not be taken at this time, as it considers its listed functional requirements and conditions as an adequate basis for the utility tariffs. Staff warns that protection equipment is still evolving and detailed regulations might impede such evolution. Staff states that it would be under a considerable burden if it has to develop such standards. Staff describes the tariff approach as less cumbersome and possibly leading to more rapid adoption of equitable and standardized rules. Staff

suggests that the utilities should be given the opportunity to work cooperatively with QFs in developing such rules and that we consider a general order only if this approach fails.

As the final point in this regard, staff addresses the question of what requirements should be imposed on QFs regarding liability and indemnification. Staff recommends that utilities be permitted to include provisions that restate common law principles of liability and indemnity in QF contracts. Under staff's approach, utilities may require a QF to provide proof of liability insurance coverage in a commercially reasonable amount not to exceed a reasonable estimate of the utility's relevant actual risk of loss. This requirement would be waived where the QF is 20 kW or less, providing its generator delivers power to the utility grid through a dedicated transformer. Staff proposes that utilities may require a QF to name the utility as an additional insured under the QF's liability insurance, except when such naming makes it impossible for the QF to obtain liability insurance or in cases where the QF is 100 kW or less in size.

C. Utility Responses

PG&E agrees generally with staff's identified functions of protective equipment. PG&E suggests that "harmful wave forms" be added as an additional adverse condition that the QF is required to provide protection against.

PG&E agrees generally with staff's discussion of QF and utility responsibilities. However, PG&E does propose to allow utilities to require QFs of 1 MW or larger to use utility grade interconnection equipment, while QFs of less than 1 MW may employ industrial quality interconnection equipment that meets state and local codes.

PG&E proposes to expand the scope of staff's treatment of small QFs to allow utilities to require QFs to maintain records of when the unit was not available for operating

maintenance outages, trip operations due to faults, and other unusual events, and to allow the utilities to reserve the right to review such records.

Edison objects to staff's suggestion that "industrial quality relays" are adequate for all interconnection protection, regardless of size. Edison states that there are good reasons to employ utility quality devices in specific instances where close coordination of the utility and QF protective devices is required to maintain reliable service from the QF and the utility. Edison claims that large QF generators are significant sources of short circuit current when connected to a distribution system and must be closely coordinated with existing utility relays to ensure reliable operation and avoid false operations. In many cases industrial grade relays do not have the necessary flexibility, stability, or calibration accuracy to allow coordination with utility system relays.

Regarding the respective responsibilities of the QF and utility with respect to equipment design, installation, operation, and ownership, Edison recommends that operators who elect to provide the interconnection protective equipment themselves shall be responsible for any damage or injury to the public, utility personnel or equipment, or to other utility customers and their equipment, caused by the generating facility. If the operator elects to have the utility provide the equipment, the utility shall be responsible for such damage or injury.

Edison characterizes staff's recommendation regarding liability and indemnity provisions as "acceptable as far as it goes." However, Edison claims that the common law has been supplemented to some extent by statutory law and suggests that a restatement of that statutory law appear in contracts. In particular, Edison refers to an alleged obligation to reimburse the indemnitee for all costs incurred or all out-of-pocket costs or all judgments paid or

all demands suffered, including appropriate attorney's fees and other costs of litigation.

SDG&E agrees with staff's recommended functional standards. However, it does not agree that staff's proposed condition (e) is required for QFs under 200 kW, because most customers at that level are expected to connect to its system with a delta wye transformer.

SDG&E agrees that the QF has responsibility for protecting its own system, equipment, the public, and utility operating personnel. It further agrees that QF designs for interconnection should be subject to utility review for functional adequacy. SDG&E offers its own schedule for review, suggesting a minimum of six and a maximum of eight weeks. SDG&E does not agree that the QF should have the option of paying the utility to install interconnection protection equipment. SDG&E objects that the QF should not be allowed "to transfer the funding of this responsibility to the utility."

With regard to liability and indemnification issues, SDG&E states that staff's reference to common law is neither helpful nor appropriate. SDG&E suggests that utilities and cogenerators should be permitted to continue as they have in the past to write indemnification provisions as they feel necessary.

SDG&E objects to staff's treatment of QFs of very small QFs that provide power to the grid through a dedicated transformer. SDG&E states that size has little to do with the extent of liability which may be incurred by a QF due to an accident. SDG&E asserts that, as the size the the QF diminishes, the need for insurance increases because the QF's own resources tend to be smaller. Based on the same reasoning, SDG&E opposes staff's recommendation that small QFs be excused from naming the utility as an insured under specified circumstances.

D. Third Party Comments

CEC agrees that this Commission should take definitive action regarding interconnection and parallel operation to establish as much standardization as feasible. CEC states that staff did properly require the QF to protect against electric service degradation, equipment damage, and harm to others by providing a series of events for which protection must be provided. However, CEC complains that staff left the establishment of the actual criteria to the utilities. CEC suggests that interconnection requirements may be appropriately considered in a separate proceeding because of the complexity of the issue, but should not be left unresolved.

Union is concerned that utilities may impose costly and unnecessary burdens on QFs in the absence of clear interconnection guidelines. Union states that interconnection costs should be net costs and the Commission should incorporate an appropriate discount factor in order to recognize that some interconnect costs would have been incurred if the utility had constructed its own facility. Further, Union proposes that the utility's ability to oversee and approve the technology and equipment selection of a QF should be narrowly confined.

As stated above, MPS requests that we provide for evidentiary proceedings to investigate and adopt standards to ensure system safety and reliability of interconnected operations. MPS states:

> "This Commission should recognize that the control methods available to QFs inherently limit the technological opportunities which can be safely and economically developed and offered in the marketplace."

MPS objects to the unilateral imposition of burdensome or incompatible control methods by utility personnel who are neither qualified nor familiar with the technologies to which these methods will be applied.

Mr. Holbrook of Power Towers, Incorporated (Holbrook), observes that, of the several utility intertie proposals, staff seems to endorse the most stringent. In particular Holbrook objects to the isolated transformer requirement as technically unnecessarily and economically devastating to many potential applications for wind power. Holbrook also describes the difficulties of a wind generator vendor and buyer where a third party (the utility) is in a position to subsequently determine the feasibility of a facility.

Henwood states that there will be honest differences of opinion between QFs and utilities regarding appropriate types and quality of interconnection facilities. Since these differences can have rather significant cost impacts, Henwood states that Commission review of utility interconnection requirements is necessary to reach an equitable solution.

Henwood argues that the only way the QF can maintain control over interconnection costs is to have the option to design, construct, and maintain is own interconnection facilities.

Henwood objects to the utilities being named as insured, as suggested by staff, because of the cost to the QF.

Pan Aero states that the QF should have several options regarding interconnection costs, including: (1) to pay for its interconnection equipment and to own and maintain such equipment; (2) to pay the utility monthly charges for utility ownership and maintenance of interconnection equipment; and (3) to own the interconnection equipment and pay the utility only for maintenance of such equipment.

Pan Aero points out that under the staff recommendation, the QF must protect its own equipment from faults on the utility system, as well as protect the utility and its ratepayers from faults in the QF's system. Pan Aero contends that the QF should have no greater burden than the utility, and asks: "If the QF must protect the utility, why

shouldn't the utility also protect the QF from faults in the utility system?"

Great Western suggests that the Commission should keep in mind the cost of interconnection equipment and the burden such costs can impose on QFs. Great Western agrees that the QF should have the option of owning and installing the interconnection equipment and that the utility should pay for any equipment the utility installs above the standard. Great Western asks that the Commission be prepared to resolve any disputes between QFs and utilities concerning the adequacy of proposed interconnection plans.

Great Western argues that there is no need for indemnity provisions. It claims that so long as each party acts with due diligence and in accordance with good engineering practice, each should have no liability to the other. Neither the utility nor the QF should be required to assume greater responsibility for losses resulting from its acts or the failure of its equipment. With respect to liability insurance, Great Western asks that such requirements be limited to preclude utilities from imposing onerous requirements on QFs.

E. Discussion

As stated above, the effectiveness of the standard offer will be substantially impaired if the parties nevertheless must negotiate terms and conditions of the physical connection to the utility network. We therefore believe that general uniform interconnection safety standards should be specified. A rulemaking proceeding such as this is a proper vehicle for adoption of policy guidelines for interconnection which assure integrity of both the utility and QF systems consistent with public safety.

As indicated above, staff has identified several standards which are essential for maintaining safety and reliability. No party has effectively disputed these standards, and we shall adopt them. Each utility should file parallel gener-

ation tariffs which incorporate the staff-recommended reliability standards plus a prohibition on harmful wave forms. The tariffs should incorporate compatible interconnection guidelines currently in effect, and should specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW. We agree with staff that for small QFs under 100 Kw, simpler requirements should apply. We therefore find reasonable the dedicated transformer requirements and reporting standards recommended by staff for QFs under 100 kW. Similarly, we expect simplified interconnection requirements for QFs between 100 kw and 1 MW. For all QFs, diagrams of illustrative interconnection configurations should be included.

We expect that the QF will attach interconnection equipment which is compatible with the protective standards incorporated within the utility's parallel generation tariffs. We agree with staff that the QF has responsibility for conforming to these standards to assure system integrity and safety. By placing this responsibility upon the QF we do not believe it necessary to endorse any specific type of interconnection equipment so long as the QF's equipment meets the protective standards outlined. We expect, however, that QF equipment will meet applicable and local safety codes. Except for the utility manual disconnect and feeder reclose blocking equipment, the QF shall have the options of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so. With this option the QF can maintain a degree of control over interconnection costs. Costs of equipment in excess of the minimum standards we have prescribed should be borne by the party requesting the equipment.

Liability and indemnification provisions contained in the standard offer should restate principles of common law and current statutes. We believe it appropriate for a QF to provide coverage at a commercially reasonable amount, consistent with the utility's actual risk of loss. In addition it is reasonable to require QFs over 100 kW in size to

name the utility as an additional insured under the QF's policy, except when such naming precludes the QF from obtaining liability insurance. This requirement is consistent with generally recognized practices in commercial contracts.

The tariffs which the utilities shall file will be subject to preliminary review by our staff, and accepted for filing on an interim basis. Unique situations should be handled by a deviation procedure under General Order 96-A. We make these tariffs interim in recognition that interconnection requirements are still evolving. We make no final judgment at this time regarding specific technical requirements necessary to assure operating reliability. We recognize that wide differences of opinion exist as to particular requirements which may need to be the subject of a general order. Accordingly, after six months we shall review these tariffs to assess their effectiveness, and, at that time, shall determine whether more detailed requirements are appropriate.

VIII. Interconnection Costs

A. Introduction

FERC Regulation Section 292.306 provides that each QF shall be obligated to pay any interconnection costs which the State regulatory agency may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics. The State regulatory agency shall determine the manner for payment of interconnection costs, which may include reimbursement over a reasonable period of time.

FERC Regulation Section 292.101(b)(7) defines "interconnection costs":

> " 'Interconnection costs' means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility

> directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs."

There is an obvious relationship between certain of these costs and the standards of operating reliability discussed above.

B. Positions of the Parties

Staff states that in order to determine what are reasonable interconnection costs it is first necessary to determine what are the minimum acceptable interconnection standards.

Staff recommends that a procedure similar to the special facilities provisions of existing tariff schedules should be established for interconnection costs. Staff proposes that the QF have the option to either: (1) advance to the utility the estimated net installed cost of the interconnection facilities and also pay the monthly cost of interconnection ownership charges as authorized in the utility's interconnection tariff, or (2) not elect to advance the estimated installed cost of the interconnection facilities and instead pay a monthly combined charge for added facilities as authorized in the interconnection tariff. Such a charge would cover both facilities and ownership costs. With the second option, the customer agrees to pay the net unpaid balance, including interest, of the installed cost of the interconnection facilities, plus removal charges, less estimated salvage value. Staff proposes that CP National Corporation

be excused from this approach on account of its status as a buyer of its entire requirements in California. Instead, CP National Corporation could include the method of payment either in its contracts with individual QFs or in separate facilities contracts.

PG&E agrees with staff's recommendation, with certain modifications. PG&E suggests that when an agreement is terminated, the QF may be entitled to a refund of part of its advance payment to the utility. PG&E proposes that the QF may be required to make an additional payment to cover the cost of the equipment removal and outstanding installation expenses.

Edison states that although staff's list of protective functions is relatively complete, specific instances will require additional equipment, most likely in the cases of large generators. In such cases Edison contends that the need for the equipment will be apparent and the utility and QF will mutually agree that it is necessary. Edison suggests that the QF should pay for the equipment in such cases.

SDG&E states that the costs of interconnection as specified by the utility should be borne by the QF. If the Commission finds that SDG&E's interconnection guidelines are not reasonable, SDG&E is "willing to discuss revisions" to its interconnection guidelines.

SDG&E objects to staff's proposal that the QF have the option to obligate the utility to make a capital investment for interconnection costs. SDG&E states that to require the utility to add this funding burden to its other capital requirements negates one of the largest benefits of cogeneration. SDG&E suggests that utility funding be at the option of the utility.

C. Discussion

The basic proposition is straightforward. Each QF is responsible for the cost of interconnection which exceeds

the cost the utility otherwise would incur to connect the QF as a customer. The costs of interconnection borne by the QF shall be only those costs necessary to meet the minimum reliability standards discussed above. The cost of additional requirements imposed by the utility shall be borne by the utility.

We are satisfied that staff has provided a sound payment basis, as modified by PG&E. SDG&E's concern regarding the possible financial burden of utility financing can be taken into account in calculating avoided costs, if an evidentiary basis can be shown.

Some QFs, particularly smaller ones, may require distribution-type line extensions. Wherever such line extensions are comparable to those serving residential or commercial customers, the charges to the QF should also be comparable to those charged other utility customers, including refunds to customers. Distribution-type line extensions costs presently are covered in utility Tariff Rules Nos. 15, 15.1, and 15.2. Unless the QF's load characteristics on any line extensions required for the QF are different than for regular utility customers, the line extension costs should be the same for each to avoid discriminatory pricing practices.

IX. System Emergencies

FERC Regulation Section 292.307 provides that a QF shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act. During any system emergency an electric utility may discontinue (1) purchases from a QF if such purchases would contribute to such emergency; and (2) sales to a QF provided that such discontinuance is on a nondiscriminatory basis. A "system emergency" is a condition on a utility's system which is likely to result in imminent

significant disruption of service to customers or is imminently likely to endanger life or property.

There is little discussion of this point among the parties. The standard offer adopted by this decision for as-available electricity does not obligate the QF to be available during an emergency. Staff states that there are adequate incentives built into pricing offers to encourage QFs to be online when system emergencies are likely to occur.

Capacity payments for firm capacity under standard of

fers neither obligate the QF to separate its load and resources nor obligate QFs to curtail their own load during emergencies. The added costs of such separation of the load and resource would be excessive and of questionable value. QFs that continue to buy power from the utility in excess of their generation, through standby rates or under a simultaneous purchase and sale arrangement will, of course, be subject to curtailment in accordance with systemwide curtailment policies as established by the Commission. To qualify for a firm capacity payment, however, the QF will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peakload periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment, fuel, or other source of energy. Capacity, in excess of the QF load, should be available to the utility during emergencies to the extent the utility can use the electricity and it is practical for the QF to make delivery.

Utility Incentives

We believe that one idea not addressed in this proceeding deserves consideration. In most markets, brokers receive a fee for their role as intermediaries between buyers and sellers. Similarly, it could be argued that utilities in their roles as intermediaries between QFs and ratepayers should receive a small fraction of the avoided cost payment as a brokerage fee. For example, utilities might

receive one-half of one percent of the avoided cost payment, leaving QFs with the remaining 99.5 percent. We specifically are not suggesting here that consumers pay an additional payment to utilities beyond the avoided cost. We invite interested parties to comment within 45 days on whether utilities should receive such a fee as an incentive for good performance in their role as a broker. We would also be interested in any specific proposals for establishing such fees.

X. Implementation

In this decision, we have decided that a qualifying facility should be presented with options in the standard offer, each of which is consistent with avoided cost principles but which also has different terms and conditions to meet different needs of the qualifying facilities. The options we order in this decision today do not exhaust the different arrangements that we can envision that are consistent with avoided cost pricing. We may conceivably order others in the future, or refine those adopted prospectively as appropriate.

As we stated earlier, additional hearings are required to complete this process. However, some offers are similar to those that have been filed already by the utilities in response to Resolution E-1872 (March 4, 1980), and we expect that these offers can become available without prolonged review. Others will require further hearings. Specifically, the "as-available" offer and the offer for firm capacity (based on the short-run marginal cost methodology) should be implemented quickly, while the levelized, escalating, and resource plan-based offers will require more extensive hearings.

Accordingly, we adopt the following schedule for submission.

Each respondent shall file the offers for (1) as-available energy and capacity and (2) firm capacity (based on the

short-run marginal cost methodology) with this Commission as an application within 45 calendar days from the date of this order. The offers should include contract terms and conditions complying with the guidelines developed in this decision. Utilities filing these applications shall serve them on all parties to this proceeding.

Because the forms of the as-available and firm capacity offers are similar to the interim price schedules currently being offered by the respondents under Resolution E-1872, and because the information to support the prices contained in these offers is developed in general rate cases, these offers may take effect expeditiously. The staff will review these offers upon filing, and the offers will take effect two weeks after the date of filing unless the Commission acts to suspend any of the offers, pending review at hearing. QFs may accept these offers as soon as they become effective, and costs incurred by utilities pursuant to the resulting contracts are reasonable and may be recovered in the same fashion as other purchased power costs.

Each of these offers will be reviewed in subsequent evidentiary hearings which may result in prospective modifications to the offers but which in no way will affect either the validity of contracts resulting from the initial standard offers or the utilities' recovery of their costs under such contracts. These evidentiary hearings, furthermore, will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will *not* be a forum for reexamining the issues resolved in this decision. QFs who believe that beneficial modifications to the standard offers may result from the evidentiary hearings may accept the utilities' initial standard offer for a short term and later accept any modified offer upon the expiration of the initial contract. A QF who is satisfied with a utility's initial standard offer may contract for a longer term with

the assurance that any later modifications will be prospective only and will not alter its agreement with the utility.

In D.93054 dated May 19, 1981 (as modified in D.93393 dated August 4, 1981), we required a provision in respondents' interim price schedules which gave QFs who entered into contracts with utilities after May 19, 1981 and before the conclusion of this proceeding the option of amending their agreements to conform with "the final decision and order" in OIR 2. Because such QFs were apparently somewhat satisfied with their agreements with the utilities, and to avoid excessive amending of these agreements, we determine that the proper time for consideration of conforming amendments is the completion of our evidentiary review of the appropriate standard offer. Thus, after we have reviewed, for example, a utility's standard offer for as-available energy and capacity and have ordered any necessary modifications, a QF who had earlier contracted on an as-available basis with that utility may convert its contract to the new standard contract. Such a QF need not, of course, wait until the completion of our review of all forms of the standard offer before exercising its option.

The other standard offer contracts (e.g. levelized, escalating, and resource plan-based contracts) adopted in this decision will require more extensive hearings. These offers shall be submitted as applications to the Commission under the guidelines set out above within 90 calendar days from the date of this order and shall be served on all parties to this proceeding. We will hold prehearing conferences in those proceedings after they are filed, and determine the scope of the subsequent hearings.

Findings of Fact

1. The California Legislature and the Public Utilities Commission have a longstanding demonstrated interest in promoting cogeneration and small power production.

2. Cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of PURPA.

3. Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under Section 201. PU Code Section 2821 enables the CPUC to establish equitable charges for purchases of power from private energy producers.

4. For such purposes electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers.

5. Section 210 also requires electric utilities to provide electric service to QFs at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

6. Section 210 further requires the FERC to prescribe rules as FERC determines necessary to encourage cogeneration and small power production.

7. On February 19, 1980, FERC issued its final rules implementing Section 210. These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere.

8. The implementation of the Section 210 rules is reserved to the appropriate state regulatory authorities.

9. By OIR 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards under the FERC rules, to further implement our decision in D.91109, and to discharge our responsibilities under PU Code Section 2821.

10. Among the criteria describing a QF under Section 201 is a limit of 50% utility equity ownership interest.

11. Utility ownership of a QF will require scrutiny of the relationship between the utility and its affiliate.

12. Utility ownership of an energy resource developed by a nonutility QF does not defeat the application of avoided cost principles.

13. The profitability of sales of a utility-owned resource to a QF should be considered in a general rate case.

14. Sierra and PP&L are unique, in view of their relative size, location, and system configuration.

15. A water diversion does not involve the direct sale of electricity by a QF and therefore is beyond the scope of this proceeding.

16. Under the FERC rules, each regulated utility is required to file projections of its incremental energy and capacity costs and its construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs.

17. FERC rules require certain specified factors to be taken into account to the extent practicable in determining avoided costs.

18. FERC rules require certain specified data to be filed by electric utilities for the purpose of avoided cost calculations.

19. Additional data, as proposed by staff, would be valuable in developing standard offers and in aiding QFs in forecasting the direction of avoided costs over time.

20. CP National buys its electrical requirements from PG&E and Nevada Power Company.

21. Social costs are tangible but hard to quantify factors that are difficult to include in avoided cost calculations.

22. FERC rules provide for a standard offer for purchases by a utility from a QF.

23. FERC rules provide that utility purchases from a QF shall be at the utility's avoided cost.

24. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity.

25. Purchases by an electric utility from a QF under a standard offer are recoverable through ECAC or other appropriate procedures without further review.

26. The standard offer is a choice of contract terms at the QF's sole option.

27. The QF may choose to provide firm energy or capacity, based on either the utility's avoided costs at the time of delivery or the time the obligation is incurred.

28. The QF may choose to provide energy as-available, based on the utility's avoided cost at the time of delivery.

29. Calculation of the utility's avoided energy cost at the time of delivery is based on the variable cost of providing an additional unit of electricity.

30. As-available energy payments are properly differentiated by time-of-use.

31. Transmission and distribution costs are not practically treated on an individual basis and should be treated in the aggregate.

32. Costs or savings resulting from variations in line losses should be aggregated for standard offer purposes.

33. The "reduction in demand" model is a useful tool for analyzing whether QFs should receive a capacity payment for the delivery of as-available energy.

34. Aggregate capacity value is recognized by the "reduction in demand" approach consistent with FERC regulations.

35. The higher the payment for capacity associated with as-available energy, the more likely such capacity will be provided during system peaks.

36. QF production will grow in increments that will provide an opportunity to prove reliability through experience.

37. The impact on the system of the failure of individual QFs is not comparable to the impact of the failure of a large central station facility.

38. Calculation of the utility's avoided capacity cost at the time of delivery is based on the utility's estimate of current shortage costs.

39. As-available capacity payments should be based on performance, adjusted by time period, and paid in cents per kWh.

40. The as-available capacity payment is based on 100% of the annual capacity value of the utility's current shortage costs.

41. As-available capacity costs include generation and generation-related transmission costs.

42. Contract length, notice, termination, and sanction provisions are not related to as-available capacity value.

43. Capacity payments for as-available hydro should not differ from other technologies.

44. The option for the QF to be paid based on costs calculated at the time the obligation is incurred allows a QF the certainty of a known price.

45. The energy component in a long-term contract is based on forecasted short-run marginal operating costs.

46. FERC rules allow for levelized energy payments.

47. Estimates of future fuel costs are an integral part of utility resource planning.

48. Forecasted energy payments for up to five years are reasonable.

49. Levelized energy payments are not an appropriate payment option under the standard offer.

50. To the extent that an individual QF provides firm capacity that allows additional costs to be avoided, these additional costs should be reflected in a higher payment to the QF.

51. The firm capacity payment associated with a short-run energy cost is based on a short-run marginal cost methodology in which the capacity payment reflects the costs of a shortage to the utility.

52. Firm capacity payments properly reflect the QF's availability during peak periods, including: dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies. The value of these factors should be computed on a cents per kWh basis as well as a dollars per kW per year basis, so that a QF that exceeds reliability standards will be paid accordingly.

53. The payment for firm capacity should be uniform to all QFs, except hydro.

54. Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability.

55. The firm capacity value of a hydro QF is reasonably based on an average of the five lowest flow years.

56. Payment for firm capacity should differentiate between small hydro producers based on actual stream flows.

57. A levelized firm capacity payment for up to thirty years is reasonable.

58. Up-front capacity payments would introduce an element of substantial risk into the standard offer.

59. Loans and guarantees greatly increase the expense to the ratepayer and should be provided only after a thorough evaluation of the proposed project.

60. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment always has some positive value.

61. FERC rules provide that utility purchases are not required during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

62. Economy energy purchases are not a condition that permits a utility to refuse to purchase from a QF.

63. The right to refuse purchases from QFs arises only when the avoided cost at the time of delivery would be less than zero.

64. The QF is entitled to reasonable notice prior to a utility's refusal to purchase.

65. Notice to baseload or intermediate QFs of a utility's refusal to purchase at least 48 hours is a reasonable minimum. Two hours notice is reasonable for QFs with peaking-type plants.

66. Utilities should set priorities, as proposed by staff, for refusals to purchase from QFs.

67. Before refusing to purchase the utility should undertake to make economy sales on behalf of the QF. In such cases the QF is paid based on the economy energy price and no wheeling charge may be imposed by the utility.

68. A report should be filed annually by each utility regarding refusals to purchase from QFs.

69. Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own

generation to the utility while purchasing its requirements from the utility.

70. Generally, the QF should be able to convert to and from simultaneous purchase and sale subject to reasonable notice and compensation provisions. QFs which select the option of forecasted or levelized energy payments under a long-term capacity contract must commit their entire output to the utility.

71. FERC rules require standard rates for purchases from QFs with a design capacity of 100 kW or less.

72. The standard offer for small QFs should be expressed in terms of cents-per-kWh and be offered on either a time or nontime differentiated basis.

73. The small QF should have the choice whether to have time differentiated payments, subject to paying for the necessary meter.

74. Time differentiated metering will be required for small QFs electing the simultaneous purchase and sale option and QFs selling a majority of their power to the utility under the sale of surplus power option.

75. Advance review will reduce the utility's risk in signing nonstandard contracts.

76. Payments under nonstandard contracts are recoverable through ECAC or other appropriate proceedings upon a showing of reasonableness.

77. A contract negotiation schedule would be difficult to enforce.

78. Wheeling can make a material contribution to cogeneration and small power production.

79. FERC rules require that each utility provide: (1) supplementary power; (2) backup power; (3) maintenance power; and (4) interruptible power.

80. FERC regulations provide that the rate for sales of backup or maintenance power should not be based on an assumption that QFs will fail to provide power simultaneously or during system peaks, or both.

81. QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF.

82. Standby rates should not be a major factor in a QF's decision whether to elect simultaneous purchase and sale.

83. Current basic standby rate levels in dollars per kW per month are reasonable as modified in this decision and may reasonably be increased in general rate cases in proportion to increases in per kW capacity costs.

84. The elimination of standby charges for months in which a QF attains an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times.

85. Standby rates should be derived residually, based on the calculation of avoided costs and the determination of retail rates.

86. Since payments to QFs are based on the utility's avoided costs, a QF that is undergoing maintenance during peak periods foregoes payments at the most lucrative time.

87. It is premature to develop standby rates for QFs not currently served by rate schedules with demand schedules.

88. Standby rates should generally be extended to all QFs with demand schedules. They should not be finalized for new technologies like photovoltaics until more analysis is possible.

89. It is reasonable to establish time-of-use-based standby rates to distinguish the impact of QF failure upon

a utility. On-peak failure is appropriately accounted for with a demand payment with a three-month ratchet.

90. QFs that contract to provide firm capacity are properly subject to the utility's scheduling requirements.

91. The provisions set forth in PG&E's Special Condition 2 to Schedule S-1 provide a reasonable standard for scheduling maintenance and exemptions from added demand changes.

92. Some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the nature of the QF's operations.

93. It is reasonable that QFs with seasonal operations shall pay added demand charges with a three-month ratchet if they cannot coordinate maintenance with a utility's schedule.

94. Interruptible rates should be available to larger QFs on time-of-use rates.

95. Interruptible service can provide both capacity and energy savings.

96. FERC rules provide for reasonable standards to ensure system safety and reliability of interconnected operations.

97. Such standards are crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of energy and capacity.

98. Staff has identified various functional standards which are essential for safe and reliable operations.

99. FERC rules require that each QF shall be obligated to pay any interconnection costs which the state regulatory agency may assess against the QF on a nondiscriminatory basis.

100. Interconnection costs are related to reliability standards.

101. Interconnection facilities are analogous to special facilities provisions of existing tariffs.

102. FERC rules require a QF to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act.

103. Adequate incentives are built into standard offers to encourage QFs to be on-line when system emergencies are likely to occur.

Conclusions of Law

1. The rulemaking procedure is an appropriate vehicle for establishing standards governing prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities under FERC rules.

2. Motions by Edison, SDG&E, and MPS are denied.

3. A QF owned in part by an electric utility is eligible for full avoided costs under the conditions adopted in this proceeding.

4. Utilities and QFs remain free to negotiate contracts containing terms which differ from those of the standard offer.

5. Additional data as proposed by staff is useful in validating the avoid cost methodology.

6. The standard offer should provide for a capacity payment for as-available energy.

7. The standard offer should provide for a forecasted energy payment.

8. A QF willing to commit to provide firm capacity should receive a higher capacity payment than a QF on an as-available basis.

9. The standard offer should provide for a levelized firm capacity payment for up to thirty years.

10. The standard offer should provide for prices based on long-run marginal cost.

11. Loans and guarantees should not be included in the standard offer.

12. Refusals to purchase should be arranged by technology and reasonable notice should be provided.

13. Simultaneous purchase and sale should be at the QF's option, subject to reasonable conditions.

14. The standard offer should provide for simplified rates for QFs of 100 kW or less.

15. Section 2821 of the Public Utilities Code does not require advance review of nonstandard contracts.

16. A utility's willingness to wheel should be considered as part of its overall conservation activities.

17. Utilities should offer supplementary power, standby power, maintenance power and interruptible power consistent with this decision.

18. The Commission should entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. A utility found not to have bargained in good faith would stand in violation of this order and will be open to potential punitive action by this Commission.

ORDER

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, each utility shall file the following data:

a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel (s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

e. The estimated operation and maintenance, administrative and general, and all other fixed

and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental fuel increases, incremental heat rates and such, will be stated.

2. Within 45 days of the effective date of this order, each utility shall file by application and serve upon all parties to this proceeding, a standard offer for as-available energy and capacity, and for firm capacity based on short run marginal cost methodology.

3. The above offers shall become effective two weeks after the date of filing, unless otherwise suspended by the Commission. Prior to compliance hearings, these offers shall be considered initial offers. Upon becoming effective, utilities shall send copies to all QFs negotiating contracts and all persons having requested copies of their price offers.

4. A QF or utility which signs an initial offer may not modify such offer until the term of the resulting contract expires. Any later modifications made by the Commission to the utility offers will be prospective only and will not alter the terms of the initial offer.

5. A QF which has contracted with the utility after May 19, 1981, and before the filing of the initial offers may modify its contract to conform to the standard contract adopted by the Commission after evidentiary hearing.

6. Utility offers for as-available energy and capacity shall, among other things:

a. differentiate payments to QFs by time of use

b. pay for capacity in cents per kWh produced

c. include transmission and distribution costs in the aggregate

d. include costs or savings from line losses in the aggregate

e. recognize the aggregate capacity value of QFs

f. base capacity payments on 100% of the annual capacity value of each utility's estimate of current shortage costs

7. Each utility shall file annual capacity payments differentiated by time of use based on the 1982 estimated cost of peaking capacity.

8. Utility offers for *firm energy* and capacity shall, among other things:

a. allow QFs the option of receiving avoided cost energy payments at the time of delivery or at the time the contractual obligation is incurred.

b. include the value of (1) availability during system peak periods, (2) dispatchability, (3) contract duration, termination, and sanctions, (4)

scheduling of outages, and (5) availability during emergencies, and shall be comparable to performance standards the utility would impose on its own plants.

c. base capacity on the avoided (marginal) capacity cost used in each utility's last general rate case.

d. include transmission and distribution costs in the aggregate

e. include costs or savings from line losses in the aggregate

f. base the aggregate capacity value for hydro on the average of five dry years, or on other alternatives discussed in the decision.

9. Within 90 days of the effective date of this order each utility shall file by application served upon all parties, a standard offer based on a forecast of energy payments for up to five years. This option shall be available to all QFs.

10. Within 90 days of the effective date of this order, each utility shall file, by separate application served upon all parties, a standard offer for long-term firm capacity based on each utility's resource plan. Long-run marginal cost estimates shall include all fixed costs associated with each utility's resource plan, and system marginal operating costs.

11. Each utility shall file, within 45 days of the effective date of this order, by application served upon all parties, simplified standard offers for QFs below 100 kW in size. Payment for energy and capacity shall be expressed in terms of cents per kWh and shall be offered on either a time-or nontime-differentiated basis. Capacity payments on a nontime-differentiated basis shall be 50% of the annual capacity value of each utility's estimate of current shortage costs.

12. Standard offers shall allow QFs to convert to and from simultaneous purchase and sale. However, such conversions shall be limited to once per year. The option to convert from simultaneous purchase and sale to sale of surplus shall not be available to a QF which chooses the forecasted energy payment option under either an as-available or long-term contract.

13. All payments made by utilities to QFs under the standard offer and approved nonstandard contracts shall be subject to recovery: in ECAC or other appropriate proceedings.

14. Utility purchases are not required from QFs during periods when the utility's avoided cost is negative, as defined in the decision.

15. Utilities shall, whenever possible, notify QFs of the possibility that purchases may be refused, with a minimum of 48 hours notice to QFs with baseload or intermediate plants, and a minimum of two hours notice to QFs with peaking plants.

16. Curtailment for reason of nonpurchase shall be for QFs of 1 MW or larger only, and shall occur in the following order:

a. Small power producers who can inventory fuel;

b. Topping cycle cogenerators who can bypass the electric generation and save some fuel; and

c. Bottoming cycle cogenerators and small power producers.

17. Each utility shall file annually a report regarding periods during which purchases were refused for the previous year. Utilities subject to ECAC shall file in conjunction with their annual reasonableness review. PP&L shall file yearly, beginning January 31, 1983.

18. Existing standby rates shall be extended to all QFs with demand schedules. Standby charges shall be waived where the QF attains an 85% capacity factor in a given month.

Each utility shall file within 45 days alternate standby rates with a three-month ratchet for QFs on time of use rates.

19. PP&L, Sierra, and CPN shall file standby rates which recognize the seasonal operations of certain QFs in their service areas. Such rates shall provide for a three-month demand ratchet.

20. Edison and SDG&E shall expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum. PG&E shall offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers.

PP&L, Sierra, and CPN shall provide interruptible service to large QFs on a contractual basis.

21. Each utility shall file with its standard offer interim parallel generation tariffs which specify interconnection reliability and safety requirements. These tariffs shall incorporate the functional standards adopted in this decision. The tariffs shall specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW.

A QF shall have the option of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so.

22. Utilities shall require QFs to pay for interconnection costs. The QF shall be granted the option either to: (1) advance to the utility the estimated cost of the interconnection facilities and also pay a monthly charge as authorized by the Commission, or; (2) not advance such additional costs and pay a monthly charge as authorized by the Commission. The QF shall pay a facility termination

charge defined as the estimated installed cost, plus the estimated removal cost, less the estimated salvage value for interconnection facilities to be removed. The utility shall deduct from the termination charge the advance previously paid, if any. If the advance paid is greater than the termination charge, the utility shall refund the difference without interest to the QF.

23. Each utility shall file a report beginning January 31, 1983, indicating the extent of wheeling performed during the previous year. Such report shall name the parties for whom wheeling was performed, include the terms and conditions, and technical arrangements of the transaction, and describe the status of any pending requests to wheel. The report shall also describe the circumstances relating to any wheeling request which was refused.

24. Nonstandard contracts shall be reviewed in the manner set forth in this decision. Advance review of such contracts shall cease two years from the date of this order, unless the Commission extends it further.

25. The standard offer shall be available to all QFs for acceptance and shall be consistent with the terms and conditions provided for in this decision. It shall remain in effect until further order of this Commission.

26. PP&L shall be exempt from filing the standard price offers ordered in this decision. Instead, PP&L shall file a standard price offer based on avoided cost principles, which is consistent with its operations. Such filing shall be made by application within 45 days from the effective date of this order and shall be served upon all parties to this proceeding.

27. Sierra shall be exempt from filing standard price offers for QFs over 100 kW

28. Each utility shall bargain in good faith with QFs.

29. Each utility shall undertake outreach efforts to assure all potential QFs are aware of opportunities available

pursuant to this order. Particular emphasis should be placed on notice to small business and minority organization.

This order is effective today.

Dated January 21, 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew present but not participating.

APPENDIX A

LIST OF APPEARANCES

Respondents: *Robert Ohlbach* and David L. Ludvigson, Attorneys at Law, for Pacific Gas and Electric Company; *Eucene Wagner,* Attorney at Law, for Southern California Edison Company; Stoel, Rives, Boley, Fraser & Wyse, by *Thomas Nelson,* Attorney at Law, for Pacific Power & Light Company; *Margaret Sullivan,* Attorney at Law (Colorado, Iowa), for San Diego Gas & Electric Company; and *John Vetromile,* for CP National.

Interested Parties: *Laura B. King,* for the Natural Resources Defense Council (NRDC); Morrison & Foerster, by *Alan Cope Johnston,* Attorney at Law, for Great Western Malting Company/Windfarms, Ltd.; *Robert W. Schempp,* for The Metropolitan Water District of Southern California; Hanna & Morton, by *R. Lee Roberts,* Attorney at Law, for Occidental Geothermal, Inc.; *John Curtis Lakeland,* for Mass-Production Systems; *Matthew V. Brady,* Attorney at Law, for the California Energy Commission; *Harry K. Winters,* for the University of California; *Harvey M. Eder,* for Public Solar Power Coalition; Miller, Balis & O'Neil, by *Robert A. O'Neil,* Attorney at Law (Massachusetts, District of Columbia), for the City of Alameda (Bureau of Electricity); *Bryan Gross,* for South San Joaquin and Merced Irrigation Districts; *C. Hayden Ames,* Attorney at Law, and Carthrae M. Laffoon, for Geothermal Generation, Inc.; P. R. Mann & Associates, by *Philip R. Mann,* Attorney at Law, and Robert E. Burt, for the California Manufacturers Association; *James W. Gruebele* and Gray Olsen, for the Dairyman's Cooperative Creamery Association; *Bert Brook,* for the Hudson Lumber Company; *C. Edward Taylor,* for Louisiana-Pacific Corporation; *Donald Hardy, for Pan Aero Corporation; Randall*

Tinkerman, for Transition Energy Projects Institute; *Burton J. Gindler,* Attorney at Law, for Kelco; McDonough, Holland & Allen, by *Bruce McDonough,* Attorney at Law, for San Bernardino Valley Municipal Water District; *Harry Davitian,* for San Diego Energy Recovery (SANDER) Project; *David K. Takashima,* for Agricultural Council of California; *Mark Henwood,* for Henwood Associates, Inc.; *Neil K. Holbrook,* for Power Towers, Inc.; *Frank Hodgson,* for Hans W. Wynholds Company; *J. C. Solt,* for Solar Turbines, Inc.; Latham & Watkins, by *David L. Mulliken,* Attorney at Law, for Solar Turbines International; Michael McQueen, Attorney at Law, for Union Oil Company of California; and *Otto J. M. Smith* and *Kenneth R. Meyer,* for themselves.

Commission Staff: *Sara Steck Myers, Ellen LeVine,* and *Brian T. Cragg,* Attorneys at Law, and *John Quinley.*

(Notice: This glossary is intended to aid the reader in understanding this decision. Legally binding definitions must be derived from the context of the decision and applicable FERC rules.)

GLOSSARY

AGGREGATE VALUE - The value of electricity production to the entire utility system as opposed to more local conditions, e.g. avoided transmission and distribution costs may be aggregated over the utility's entire system and paid to a QF on a prorated basis without regard to its distance from the load center.

AS-AVAILABLE ENERGY/CAPACITY - Electricity provided by a QF to a utility as it becomes available, rather than at prearranged times and in prearranged quantities.

AUXILIARY POWER SOURCES (APS) - Electric generating facilities designed to be used in the event of an outage on the local utility grid.

AVERAGE COST PRICING - The pricing of electric service designed to recover the total costs on a system in order to make total revenues (including rate of return) equal to total costs. Total costs are based on costs as recorded in books of account and forecasted to be recorded in such accounts.

AVOIDED COSTS - The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

BACK-UP POWER - Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

BASELOAD - The minimum continuous load on a power system over a given period of time.

BIOMASS - Any organic material not derived from fossil fuels.

BIOMASS CONVERSION - The process of conversion of any organic material not derived from fossil fuels (such as wood waste, rice hulls, walnut shells, etc.) into electricity or energy.

BOTTOMING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production.

CAPABILITY - The maximum load which a generator, turbine, transmission or circuit, apparatus, station, or system can supply under specified conditions for a given time interval without exceeding approved limits of temperature and stress.

CAPACITY - The load for which a generator, turbine, transformer, transmission circuit, apparatus, station, or system is rated. Capacity is also used synonymously with capability.

CAPACITY COSTS - Those costs associated with capital investments in electricity production and delivery.

CAPACITY FACTOR - The ratio of average load on a generating resource to its capacity rating during a specified period of time expressed in percent.

CAPACITY PAYMENTS - Those payments which reflect the value capacity received.

COGENERATION - The sequential production of electricity and heat, steam, or useful work from the same fuel source.

COGENERATION FACILITY - Equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial heating, or cooling purposes, through the sequential use of energy.

COMBINED CYCLE - Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/generator system, thereby increasing the efficiency of heat utilization.

CURTAILMENT - A period during which a utility declines to purchase available electricity from a QF, generally due to low demand or system maintenance requirements.

DEBT SERVICE - Periodic payments due on loans made to a QF.

DISPATCHABILITY - That condition of the qualifying facility whereby, through engineering design, installed equipment, operating conditions, and procedures, the electric utility has the ability to dispatch the facility for operation at any time, in a manner agreed upon by the parities.

ECAC (ENERGY COST ADJUSTMENT CLAUSE) - Periodic adjustments of utility rates to reflect fuel and related costs.

ENERGY COSTS - Those costs associated with fuel use in electricity production.

ESCALATED PAYMENTS - A payment commitment for future years determined from forecasted rates of avoided costs.

FIRM CAPACITY PAYMENTS - Payments for electricity provided in predetermined quantities and at predetermined times, which may be based on avoided costs at time of delivery or at the time the obligation is incurred.

FIRM POWER - Power available at all times during the period covered by the commitment, except for forced outages and scheduled maintenance. Firm power is provided with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller and less expensive plant, or to purchase less firm power from another facility.

FORECAST - Future values determined by a mathematical model.

HEAT RATE - A measure of generating station thermal efficiency generally expressed as Btu per net kilowatt-hour. The average heat rate is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatt-hours generated. The marginal heat rate is calculated as the additional (saved) Btu's to produce (not produce) the next kilowatt-hour.

INCREASE IN SUPPLY - An economic model of electrical production by QFs whereby such production is viewed as increasing aggregate supply of energy, implying that QFs should be subject to operating and performance standards comparable to a utility's own generating plants for purposes of determining pricing.

INTERCONNECTION - The physical system of electrical transmission between the QF and the utility.

INTERCONNECTION COSTS - The reasonable costs of connection, switching, metering, transmission, distribution safety provisions, and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

INTERRUPTIBLE POWER - Electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

KILOWATT (kW) - An electrical unit of power which equals 1,000 watts.

KILOWATT-HOUR (kWh) - A basic unit of electrical energy equal to the use of 1 kilowatt for a period of one hour.

LEVELIZATION - A financial arrangement whereby payments are constant over a specified period and are based on forecasted values and the value of money over time.

LINE LOSSES - Losses in electricity which occur during its transmission and distribution.

LOAD - The amount of electric power delivered to a given point on a system, or total amount of demand on the system.

LOAD FACTOR - The ratio of average to peak use during a specified period of time, expressed in percent.

LOAN OR BOND GUARANTEES - A utility liability which guarantees the repayment of a bond or loan on behalf of a QF in the event that the QF is unable to make timely payments.

MAINTENANCE POWER - Electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

MARGINAL COST PRICING - The pricing of electric service designed to equate the rates for electric service with the marginal costs of that electric service.

MARGINAL COST - The change in total cost caused by a change in output. Marginal cost can also be understood as the additional cost to produce an additional unit of output, or the savings from producing one unit less of output (i.e. avoided cost).

MONOPOLY - A market structure in which there are many buyers but only one seller.

MONOPSONY - A market structure in which there are many sellers and only one buyer.

NATURAL GAS - Either natural gas unmixed, or any mixture of natural gas and artificial gas.

NONFIRM POWER - Electric power available as surplus only, which is supplied by the power producer at the producer's option and can be interrupted by the power producer at will.

NONSTANDARD CONTRACTS - Negotiated contracts between utility and a QF which do not conform to standard offer guidelines previously approved by the CPUC.

OIL- Crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products.

PEAK LOAD - The maximum electric load consumed or produced in a stated period of time. It may also be char-

acterized as the minimum instantaneous load within a designated interval of a stated period of time.

PURCHASE - The purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

QUALIFYING FACILITY - A cogeneration facility or a small power production facility which is a qualifying facility under 18 CFR, Chapter I, Part 292, Subpart B of the FERC regulations.

RATE - Any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.[1]

RATE BASE - The utility investment on which the utility is allowed to earn a rate of return.

REDUCTION OF DEMAND - An economic model of electrical production by QFs whereby such production is viewed as reducing aggregate demand for energy, implying that QFs need not be subject to utility operating and performance standards for purposes of pricing determinations.

REFUSAL TO PURCHASE - See curtailment.

REFUSE-DERIVED FUELS - Fuels derived from municipal waste used as fuel for electric energy production or low Btu gases from sewage treatment plants for use in turbines.

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[1] Rates are defined in the California Public Utilities Code to include rates, fares, and charges (§ 210). § 451 of the Code identifies rates as all charges demanded or received by any public utility for a product or commodity furnished. We recognize the FERC definition of rate to include any price for purchase and use the term rate herein to refer also to prices. However, the term price is also used in this report to allow for a separate identification, in some cases, of payments for purchases from the more traditional use of the term rates as referring to charges demanded or received under filed tariffs.

RELIABILITY - In the context of the decision, the reliability of a QF to the electrical utility and to the system, which may be determined by a specified set of standards.

RESERVE MARGINS - Extra capacity available to: (1) meet anticipated demands for power; (2) serve load in the event of a loss of generation resulting from an unscheduled outage. Reserve margin is the ratio of excess capacity to anticipated peak load expressed as a percent.

SALE - The sale of electric energy or capacity or both by an electric utility to a qualifying facility.

SIMULTANEOUS PURCHASE AND SALE - A regulatory convention that allows a QF to simultaneously sell its own generation to the utility while purchasing its requirements from the utility; an exchange of electrical flow does not necessarily occur - the difference is cash flow.

SMALL POWER PRODUCTION - Any unregulated electricity production facility as defined primarily in the FERC rules, including hydroelectric facilities, geothermal, biomass refuse-derived fuel, and wind facilities.

SOCIAL COSTS - Tangible but hard-to-quantify costs to society of an economic or technological activity.

SPINNING RESERVES - Reserves that are operated at less than the rated capacity to relieve imbalance on the system.

STANDARD OFFER - A utility offer to purchase electricity from a QF that is formed within guidelines previously adopted by the CPUC.

SUPPLEMENTARY FIRING - An energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

SUPPLEMENTARY POWER - Electric energy or capacity supplied by an electric utility, regularly used by a qual-

ifying facility in addition to that which the facility generates itself.

SYSTEM EMERGENCY - A condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

SYSTEM POWER VALUES (SPV) - PG&E's model of the marginal costs of additional capacity and energy, based in Application 58545, OII 26, and PG&E price offers on a combined cycle plant as the marginal plant.

TIME DIFFERENTIATED PAYMENTS - Payments made according to time-of-day or time-of-year delivery periods.

TOPPING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy.

TOTAL ENERGY INPUT - The total energy of all forms supplied from external sources other than supplementary firing to the facility.

TOTAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The sum of the useful power output and useful thermal energy output.

UP-FRONT PAYMENTS - Initial large outlays provided to QFs by utilities to assist in financing large capital expenses incurred for construction.

USEFUL POWER OUTPUT OF A COGENERATION FACILITY - The electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

USEFUL THERMAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The thermal energy made available for use in any industrial or

commercial process, or used in any heating or cooling application.

VALUES TO PERPETUITY - The costs (values) of owning and operating a generating plant for an infinite number of years, assuming plant replacement at the end of its useful life. Values are then levelized to the initial year.

WASTE - By-product materials other than biomass.

WHEELING - The use of transmission facilities of one utility system to transmit power to another utility system or between customer facilities within a single utility system or between utility systems.

Decision 82-12-120 December 30, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-02-103 in Order Instituting Rulemaking No. 2.	Application 82-03-26 (Filed March 8, 1982)
SOUTHERN CALIFORNIA EDISON COMPANY, application for 3 standard offers for purchase of electric power from cogeneration and small power production facilities.	Application 82-03-37 (Filed March 8, 1982)
Application of SIERRA PACIFIC POWER COMPANY, for approval of its standard offer to purchase cogeneration and small power production facilities.	Application 802-03-62 (Filed March 16, 1982)
Application of PACIFIC POWER & LIGHT COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-03-67 (Filed March 18, 1982)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power From Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.	Application 82-03-78 (Filed March 22, 1982)
Application of CP NATIONAL CORPORATION for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-21 (Filed April 8, 1982)
Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.	OIR 2 (Petition for Modification filed September 10, 1982)

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OPINION

Summary

Decision (D.) 82-01-103, January 21, 1982, established guidelines for utility purchases of electricity from cogenerators and small power producers. That decision ordered utilities to file five standard price offers each of which would be a complete contract which small power producers could sign without negotiation. The five offers were to meet the varied needs of different qualifying cogeneration and small power production facilities (QFs).

* The *as-available* offer pays an energy payment and a capacity payment in ¢/kWh varying by time of delivery. The payment is derived from utilities' short-run avoided costs (i.e., variable operating costs plus shortage value). This offer is similar to a spot market purchase in a competitive environment and requires no long-term contract-type commitment on the part of the QF.

* The *firm capacity* offer is like the as-available except that payments for capacity are based on specific performance requirements being met by the QF (including *availability* or *output* requirements). The capacity price may be fixed for up to 30 years. The offer provides some pricing certainty for those who can meet the specific performance criteria.

* The *less than 100 kW* offer is similar to the as-available, except for simplified requirements for the small facilities.

* The *five-year forecast* offer fixes energy prices for five years, providing more price certainty.

* The *long-term resource plan* based offer bases prices on new utility resources (as opposed to

short-run avoided costs). It may be used to establish price more firmly for longer periods and to pay for the full value of new resources.

The first three offers, as filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) are the subject of this decision. The utilities' standard contracts, as filed with the Commission, were reviewed during 40 days of compliance hearings in which the utilities, Commission staff (staff), and QFs participated. This decision responds to the various objections of the parties regarding pricing and standards for performance. It does not address all the issues raised in the proceeding. The remaining issues (interconnection, filing requirements, miscellaneous contract terms, insurance, and others) will be the subject of a later decision.

Given the policy of trying to create standard contracts which can be signed directly, the Commission reviewed all of the details relating to pricing and standard offer terms. The following is a summary of the specific issues addressed and resolved in this decision:

* *Payments for Capacity.* The decision adopts the full cost of a combustion turbine for capacity for long-term contracts signed at this time. It concludes that refinements to this methodology may be appropriate in the future.

* *Performance Requirements.* Regarding the specific performance requirements necessary to obtain firm capacity payments, the decision generally adopts PG&E's proposal which bases firm capacity on either *availability* (a QF agrees to produce when called upon) or *output* (a QF agrees to provide energy during 80% of a summer peak period). The QF has a choice. The proposal by Edison, on the other hand, is rejected, and the utility is asked to amend its

offer consistent with PG&E's approach, as modified by this decision. Edison's proposal, by combining both availability and output in one package, is found to be too burdensome and not in compliance with D.82-01-103. SDG&E's two offers are both found not to be in compliance. SDG&E is also directed to amend its offer consistent with PG&E's offer, as modified by the decision.

* *Termination Provisions.* In the event a firm contract QF terminates, the decision finds that the QF must repay the amount it was paid that exceeded what it would have been paid had it not signed a long-term contract (the levelization overpayment). Additional provisions are established if inadequate notice is given. This approach basically follows that used by PG&E and SDG&E. Edison's reimbursement calculation is approved, but Edison is otherwise required to modify its approach in keeping with the decision.

* *Energy Payments.* The decision establishes a procedure which allows QFs to review and comment on the utilities' proposed energy rates filed each period. It also orders the utilities to include contract language which clarifies that energy payments shall be derived from the full avoided variable operating costs throughout the life of the contract. Individual issues are also resolved regarding use of average vs. actual year incremental heat rates in the calculations (average is used now, but utilities can make proposals for actual later), line loss (such losses are assumed to be similar to utility plants, but further study is requested), and curtailment (the system established in D.82-01-103 is con-

tinued with a rejection of limits on the use of this provision for now).

Introduction

This decision represents a further step by this Commission toward its stated goal of promoting the development of cogeneration and small power production facilities, alternatives to the traditional generation of electric power through the use of fossil fuels. Our policy, developed in previous decisions, will be served by this order's clarification and further definition of the proper relationship between public utilities and these alternate generation resources.

To date, the most significant proceeding in this regard has been Order Instituting Rulemaking (OIR) 2. OIR 2 was commenced to establish standards governing the prices, terms, and conditions of utility purchases of power produced by qualifying cogeneration and small power production facilities (qualifying facilities or QFs). The proceeding was stimulated by our own independent action and analysis, as well as the requirements of both state law (Public Utilities (PU) Code § 2821) and federal law (the Public Utility Regulatory Policies Act of 1978 (PURPA)). PU Code § 2821 requires the Commission to "approve and establish equitable charges" to be paid to privately owned generation facilities. PURPA and the resulting regulations adopted by the Federal Energy Regulatory Commission (FERC) specify rules governing a public utility's purchase of power from cogenerators and small power producers who qualify for the benefits of the law. The FERC regulations require state implementation.

On January 21, 1982, we issued D.82-01-103 in OIR 2. The decision ordered the major California electric utilities to file standard offers for power purchases from qualifying facilities based on avoided cost principles. We concluded that avoided cost pricing would promote the maximum efficient development of these alternative resources.

The standard offer ordered by D.82-01-103 was intended to describe not only the prices to be paid to QFs, but the rights and obligations corresponding to those prices. The standard offer is, in other words, an economic package in which the prices and the contract terms are inextricably bound together.

In order to meet the varied needs of QFs, the standard offer, designed to recognize the two basic components of a power purchase - energy and capacity, provided five different options. The options, expressed as separate offers, were further distinguished by the time within which they were required to be filed by the utilities. A shorter time frame was assigned to those offers which we felt could be reviewed more expeditiously. The offers and filing periods were as follows:

1. Within 45 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. As-available energy and capacity based on a short-run avoided cost methodology.

    b. Firm capacity based on a short-run marginal cost methodology.

    c. Energy and capacity provided by QFs below 100 kilowatts (kW) in size.

2. Within 90 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. Energy based on a forecast of energy payments for up to five years tied to either an as-available or firm capacity option.

    b. Firm capacity based on a utility's long-run marginal costs developed from the utility's resource plan.

The scope of the present proceeding is limited to those offers for which a 45-day filing was set in D.82-01-103, as listed under item 1. above. Five-year forecasted energy payments and long-term firm capacity offers will be reviewed in subsequent proceedings (Application (A.) 82-04-44, A.82-04-46, and A.82-04-47).

In D.82-01-103, the Commission outlined the procedure which would be followed in the approval of the offers filed after 45 days. Following staff review, the offers were to take effect two weeks after the date of filing unless otherwise suspended by the Commission. Each of these offers would then be reviewed in subsequent evidentiary hearings to determine the utility's compliance with D.82-01-103 and the factual basis for the prices contained in the offers. By D.82-04-071 (April 12, 1982), a subsequent order modifying D.82-01-103 and denying rehearing, all utilities were required to amend their initial filings to conform to the prescribed modifications and cure specific deficiencies identified in D.82-04-071. The presently effective offers were filed in May and July 1982.

Procedural Background

A. Prehearing Matters

Compliance hearings as required by the Commission in D.82-01-103 commenced with a prehearing conference held on May 10, 1982, in San Francisco, California. At that time, the presiding administrative law judge (ALJ) announced that at page 144 of D.82-01-103 the Commission had prescribed the scope of the hearings as follows:

> "These evidentiary hearings. . .will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will *not* be a forum for reexamining the issues resolved in this decision." (Emphasis original.)

During the prehearing conference, however, it became clear that, even with this limitation on the hearings, there remained numerous issues related to both the utilities' compliance with D.82-01-103 and subjects not resolved by that decision but relevant to the standard offers. More than 25 parties voiced their concerns and offered suggestions with how to proceed in this complex matter.

Based on statements made at the prehearing conference and subsequent written statements filed by applicants and the staff on May 14, 1982, an ALJ ruling was issued on May 19, 1982. The ruling included the following determinations:

1. To initiate hearings, the completion of staff reports related to the applications of Edison (A.82-03-37), PG&E (A.82-03-26), and SDG&E (A.82-03-78) were necessary. Several of the applicant utilities had argued that their applications were intended to comply with the orders issued in OIR 2. Therefore the response of staff or interested parties to those filings were required in order to identify the issues.

2. Following receipt of staff's report on Edison, public hearings would commence on July 12, 1982, with Edison's direct showing.

3. Hearings on the applications of Sierra Pacific Power Company (A.82-03-62), Pacific Power & Light Company (A.82-03-67), and CP National Corporation (CP National) (A.82-04-21) would be deferred until staff reports could be issued on those applications.

4. The ALJ concurred with the staff that issues to be considered in this proceeding extended to questions dealing with provisions included in the utilities' applications, although not specifically addressed by the Commission in its

OIR 2 decisions, as well as an applicant's compliance with those orders.

5. The tariffs required by D.82-01-103, Ordering Paragraphs 18 and 19 (standby rates) and Ordering Paragraph 21 (parallel generation), should be considered an integral part of the subject standard offers for purposes of assessing their compliance with OIR 2 and must therefore be made part of each of the subject applications.

B. Hearings

1. Expert Testimony

Following this ruling, 40 days of hearing were held between July 12, 1982 and October 15, 1982, in San Francisco. During that time, testimony was presented relating to the applications of PG&E, Edison, and SDG&E. Between the applicant utilities, the Alternate Generation and Rate Design Sections of the staff, state and local government agencies, and businesses and individuals presently or potentially operating or involved with cogeneration and small power production facilities, a total of 41 witnesses were called to testify. Many of these witnesses, who included experts in engineering, economics, law, and management, testified more than once during the hearings. Interested parties, representing various types of QF development, accounted for 17 of these witnesses. Seventy-four exhibits were received into evidence.

2. Statements

During the course of the proceeding, a number of individuals had expressed their desire to offer statements, as opposed to testimony, during hearing. In response to these requests, the ALJ, in noticing the hearing dates to be reserved for the testimony of interested parties, also set a specific date for public statements.

On August 30, 1982, 18 people offered their views relating to the standard offers at issue. These individuals were uniformly concerned that various provisions of the utilities' standard offers were not in keeping with this Commission's and PURPA's policy of encouraging the development of qualifying facilities. In particular, these individuals questioned the utilities' bases for the calculation of their avoided costs and the reasonableness of certain provisions of the standard offers which they considered to be penalties or obstacles to QF development.

Most of those making statements either were purchasers or sellers of small, home-sized (1 to 10 kW) and wind generators. Their chief concern was the level of insurance required of QFs under the standard offers. It was argued that the premium level exceeded both the revenue benefit to be derived from installation of a wind generator as well as any risk created by such a facility. All agreed that the present insurance requirements would stifle the growing potential of this alternate resource.

In addition to these statements, other individuals either took the opportunity during other regularly scheduled hearing days to make statements or wrote letters to the Commission on the subject. These statements and correspondence, which were most frequently industry-specific, raised concerns similar to those expressed in other testimony and comments and asked the Commission to adopt standard offers which would encourage, not discourage, QF production.

C. Consideration of Firm Capacity Methodology

During the hearings PG&E and Edison attempted to offer testimony and question the staff on the proper methodology for determining the as-available capacity and firm capacity prices to be paid to QFs. By oral ALJ ruling on July 20, 1982, all parties were precluded from addressing this issue on the grounds that the issue had been resolved in OIR 2 and was beyond the scope of these compliance

proceedings. This ruling was based on a review of the language of D.82-01-103 and D.82-04-071 in OIR 2 and consultation with the assigned Commissioner's office. On July 26, 1982 PG&E filed a motion with the Commission seeking reversal of this ruling. Edison filed a similar motion on July 29, 1982.

The assigned Commissioner concluded that this matter did not need to be referred to the Commission, but rather should be resolved by further ALJ ruling. Upon consideration of the petitions of PG&E and Edison and further review of the applicable Commission decisions, it was determined that the ALJ's ruling should be reversed in part and affirmed in part. Specifically, it was concluded that this proceeding was the proper forum for addressing the issue of the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revision of the methodology for calculating a utility's as-available capacity payment adopted in D.82-04-071, however, was reserved for the utilities' general rate cases as specified in that decision.

Testimony by all parties on the issue of the proper methodology for calculating a utility's firm capacity price was heard over a 10-day period following the presentation of all other testimony. In order to expedite the submission of this matter, certain information proposed by PG&E relating to this issue was directed to be served on the parties after the final day of hearing.

D. Submission

At the conclusion of the final day of hearing on October 15, 1981, and in an ALJ ruling issued that same date, A.82-03-26, A.82-03-37, and A.82-03-78 were submitted upon the following:

1. The submission by PG&E of an additional proposal and adjustment related to the Energy Reliability Index used by PG&E in calculating

its shortage costs on which PG&E's standard offer for firm capacity will be based.

2. The filing of concurrent briefs on November 15, 1982.

PG&E was directed to serve its proposal on all appearances in this proceeding. Any party wishing to address or request a hearing on this proposal was directed to do so in the briefs due on November 15. Requests for hearing were to include a specific identification of the basis for the request and any questions to be addressed in cross-examination.

On the final day of hearing, SDG&E was also directed to furnish a copy of its input assumption data to staff, which had formally requested it on October 15, and to the State Energy Task Force, prior to the end of the briefing schedule. According to the briefs, this material had not been received by that time.

On October 25, 1982, PG&E filed its proposal. PG&E also submitted on November 2, 1982, a recalculation of its annual Energy Reliability Index adjustment factors based on a "low" load management scenario.

Between November 15 and 17, 1982, concurrent briefs were filed by a total of 16 parties including PG&E, Edison, SDG&E, staff, the Independent Energy Producers (IEP), the California Manufacturers Association (CMA), Occidental Geothermal, Inc. (Occidental), Ultrasystems, Inc., Federal paper Board Company, Inc., the Regents of the University of California (UC), Calcogen, Inc., the California Energy Commission (CEC), the State Energy Task Force, the California Waste Management Board, Kimberly-Clark Corporation, and Simpson Paper Company. Any delays in filing were attributable to breakdowns in required support systems. Correspondence was also received at that time addressing issues similar to those presented in the briefs.

Positions of the Parties

The testimony received during hearing in this proceeding was sponsored by numerous witnesses representing a variety of interests, including those of the applicant utilities, government, and private industry. The views of 16 of the appearances regarding this record have been expressed in concurrent briefs. Other parties, although providing testimony, have chosen not to file briefs, in some cases apparently due to a lack of economic resources. Still others have addressed the issues raised during hearing in correspondence to the Commission. To provide an overall description of the parties' basic viewpoints, we have summarized the positions below.

A. Utilities

All three utilities, PG&E, Edison, and SDG&E, believe that their applications are in full compliance with this Commission's decisions in OIR 2. Each asserts that the record fully supports this conclusion.

The utilities are also of the opinion, however, that to promote the continued development of QF power, certain amendments to their standard offers may be desirable. Each utility asks that it be recognized that any suggested modifications of its standard offers do not result from a failure to comply with OIR 2, but rather are aimed at better achieving the goal of QF development.

According to their briefs, the determination or adoption of any standard offer amendment by a utility was greatly influenced by the utility's perceived responsibility to its ratepayers. The utilities believe that the PURPA mandate requiring prices paid for QF power to be just and reasonable to ratepayers is embraced in the concept of avoided cost. Under that concept, the utility is to pay the QF a price equal to the cost the utility would have incurred had it generated the electricity itself or purchased the power elsewhere. The ratepayer should therefore remain indifferent to whether the utility or the QF produces the power.

This principle of ratepayer indifference has led the utilities to conclude that a standard offer must result in a proper allocation between QFs and utilities of the risks associated with the transaction. Should business and economic risks be shifted to the utility and its ratepayers disproportionate with the benefits to be received from QF production, a ratepayer would no longer remain indifferent since that risk would ultimately be translated into additional costs to the ratepayer.

The utilities' briefs also reflect the view that the standard offer is a single, integrated economic package. SDG&E specifically advises that the division of issues in its brief is arbitrary since all of the standard offer provisions relate to price in one way or another.

B. Staff

The staff states that its primary concern is whether or not the utilities' standard offers comply with this Commission's decisions in OIR 2. Staff is of the opinion, however, that to develop effective standard offers the issue of compliance should include an examination of (1) the propriety of contract terms which the Commission has yet to direct be included or excluded from the standard offers, (2) the determination of a utility's true avoided costs, and (3) the need for standardization of contract terms between different utilities' standard offers.

Like the utilities, the staff's recommendations are intended to achieve the proper balance of ratepayer and QF interests. The risks associated with the standard offers, however, are viewed somewhat differently by the staff than by the utilities. In particular, the staff notes that the QF market is still in its infancy. This circumstance has two results - the need for continued encouragement for its development and an increase in the risks which potential investors and owners perceive are associated with a QF's operations. It is the staff's belief that ratepayers who will benefit from the increased development of alternate

energy resources should share in the risks related to this emerging industry.

C. Private Industry

This category includes a total of eight parties representing the interests of currently operating or potential QFs. Among these parties were two associations: IEP, representing a group of California cogenerators, small power producers, and related businesses, and CMA, representing industries some of whom desire to participate in QF programs and other who do not. Briefs were also filed by Occidental, Ultrasystems, Inc., Federal Paper Board Company, Inc., Calcogen, and Kimberly-Clark Corporation and Simpson Paper Company, who sponsored a joint brief.

The participation of all of these parties has focused on challenges to either the utilities' compliance with OIR 2 or their proposed methodologies for calculating their firm capacity payments, an issue included within the scope of this proceeding. Influencing the positions taken by these parties has been their particular perception of the risks associated with the utility-QF transaction and the proper allocation of those risks. It is the opinion of the industry that to require the QF to bear certain of these risks will ultimately stifle the development which the Commission specifically sought to encourage in OIR 2.

According to these parties, among the risks facing QFs is the inability to obtain financing for projects and predict, on the basis of the contract terms, what each QF can expect in the future. These concerns have been heightened by a substantial drop in avoided cost payments to QFs. This circumstance has jeopardized the operations of current producers and the projects of potential QFs.

Because of this asserted instability in the industry, QFs in their testimony and briefs have been most concerned with the utilities' methods for calculating avoided costs, the availability of data to verify those calculations, the

standards of performance required of QFs, the ambiguity and lack of standardization with respect to certain contract terms, and the utilities' assignment of particular risks to QFs, including the risk of future regulatory changes.

It is the view of the industry that QF production reduces the risks to which ratepayers would otherwise be exposed by utility operations. For this reason, it is the industry's position that QF development should not be stifled by the improper calculation of price, the absence of proper incentives, or a demand for performance which exceeds that of a utility's own plants.

D. State Government

Besides this Commission's staff, briefs were filed by four other state governmental entities: the CEC, the California Waste Management Board, the State Energy Task Force, and UC. With the exception of the CEC, each of these entities is involved directly in the development of alternate generation facilities.

The positions expressed by these parties have been formulated based on a strong desire for the continued encouragement of QF development and for the resolution of problems created by unique arrangements and resources in which the State, in certain cases, intends to be involved. With respect to this latter circumstance, this Commission has been asked to consider the special needs and benefits of projects converting solid waste into energy and the impact on the standard offer of the State itself being a party to or potential beneficiary of the agreement.

Aside from these special concerns, the views of these state entities mirror those held by the QF industry. The utilities' avoided cost calculations are questioned, while standardization of and certainty in contract terms are urged. It is the opinion of state government that its recommendations take into consideration the appropriate allocation of risks between QFs and ratepayers.

E. Positions Expressed in Testimony or Correspondence

The participation of four of the interested parties to this proceeding was limited to the receipt of their testimony; no briefs were filed. These parties included the California Wind Energy Association (CalWEA), which indicated that its financial resources for participation were limited; American McGaw, a manufacturer owning a 2,800 kilowatt (kW) cogeneration facility in California; Henwood Associates, consultants negotiating contracts and arranging financing for QFs; and the County Sanitation Districts of Los Angeles County, the City of Commerce, and the City of Long Beach, local government entities with an interest in waste-to-energy projects.

The sole purpose of the two exhibits sponsored by CalWEA was to challenge the insurance requirements of the utilities' standard offers. Because of the high cost of such insurance and the documented safety of farm- and home-sized wind generators, CalWEA has urged the modification or elimination of the utilities' insurance provisions for wind systems of 20 kW or less. The testimony of the County Sanitation Districts expressed concerns regarding waste-to-energy projects similar to those contained in the testimony and brief of the California Waste Management Board. American-McGaw's testimony covered issues and expressed opinions comparable to those of other industry representatives. Henwood Associates focused on perceived shortcomings in Edison's standard offers.

At the time of submission of this matter, Helmich Engineering, United Energy Corporation, and Hudson Lumber Company wrote to this Commission indicating their views. Mr. James E. Helmich of Helmich Engineering is an appearance of record, while the latter two corporations are members of IEP. Price fluctuation, which in one case has directly affected operations, was the primary concern of these companies. Like other individuals who have written to the Commission during the course of these pro-

ceedings, a resolution of this matter before the end of 1982 was urged to ensure the continued development of the QF industry.

Scope of the Decision

Before commencing our discussion on the issues raised in this proceeding, we must first consider two requests made by several parties regarding the scope and timing of this decision. It is the view of the QF industry that for its development to continue (1) an order resolving all of the issues relating to the subject standard offers must be reached and (2) that order must be issued expeditiously, preferably before the end of 1982. The standard offer is seen as a single, unseverable economic package, the provisions of which must be known before a QF can commence or continue its operations.

Unfortunately, with the extensive participation and record in this matter, the earliest submission data for these applications was November 15, 1982. As a result, we have been left little time to prepare an order which would resolve all of the standard offer issues this year while simultaneously giving the proper weight and consideration to all of the views presented.

For this reason, although we recognize that the standard offer provisions are interrelated, we can address in this decision only certain of the issues arising from those offers. We believe, however, that the subjects chosen, i.e., the basic price issues and certain contract provisions, will provide sufficient options for QFs to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

By adopting this approach, we will be able to consider fully the record which the parties have spent appreciable time and effort developing. All appearances should be assured, however, that those issues which are not discussed in this order will be addressed as early as possible next year.

Specifically, this decision will examine the utilities' bases for and standard offer provisions relating to capacity payments and energy payments. Our discussion of capacity and energy payments will include consideration of such issues as performance requirements, termination, and periods of curtailment. We will also consider the propriety of providing for the conversion of standard offer contracts signed after the effective date of this order to the standard offers approved in our forthcoming second opinion in this proceeding.

Capacity Payments

Because this proceeding was primarily intended to determine the utilities' compliance with our decisions in OIR 2, a basic understanding of those orders, as related to each of the issues to be considered, is critical. With respect to payments for capacity, this Commission concluded in D.82-01-103 that energy delivered on either an as-available or firm basis resulted in a utility avoiding capacity costs. Avoided capacity costs are those costs associated with ensuring the reliability of the production and delivery of electricity which the utility avoids incurring by purchasing power from a qualifying facility.

In OIR 2, the utilities had questioned whether any capacity costs are avoided when energy is delivered to the utility only as it becomes available. D.82-01-103 recognized, however, that as-available power, when aggregated, did in fact result in a reduction in demand upon the utility and thereby avoided certain capacity costs, including those associated with generation and generation-related transmission. Payments for as-available power, however, would not reflect any value for contract length, notice, termination, or sanctions since such provisions would not be part of an as-available offer.

In contrast, firm capacity was viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions.

By definition, firm power is provided in predetermined quantities at predetermined times with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to avoid the construction of a generating unit or the purchase of firm power elsewhere. A QF providing firm capacity, was determined to avoid costs additional to those related to as-available power. This result was to be reflected in the firm capacity payment.

With respect to the amount to be paid QFs for their output, D.82-01-103 requires "full avoided cost pricing of power from qualifying facilities." (Mimeo, at page 26.) For purchases of both firm and as-available capacity, PG&E, Edison, and SDG&E were directed to base their payments on each utility's estimate of its current shortage costs using a combustion turbine facility as a proxy.

Although recognizing that the combustion turbine was a somewhat less attractive methodology for firm, as opposed to as-available capacity, payments, we concluded in D.82-04-071 that revisions to the adopted methodology would only be considered in the future. For as-available capacity prices, consideration of such revisions was set for the utilities' general rate cases. No specific time, however, was identified for examining modifications of the methodology for calculating firm capacity payments. As stated previously, by ALJ filing, the proper forum was found to be this proceeding.

Because the firm capacity payment should reflect certain factors not included in the as-available capacity price, the following discussion will commence with an examination of the utilities' standard offer terms governing performance and termination in a firm capacity contract. We will then review the methods by which the utilities have calculated the prices to be paid for both firm and as-available capacity.

A. Performance and Termination Provisions in Firm Capacity Contracts

Consistent with the applicable FERC regulations, D.82-01-103 states:

> "The firm capacity payment properly reflects the factors recited in Part IV,A, above related to the availability during system peak periods, including:
>
> "a. Dispatchability,
>
> "b. Reliability,
>
> "c. Contract duration, termination, and sanctions,
>
> "d. Scheduling of outages, and
>
> "e. Availability during emergencies.
>
> "The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage the development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollars per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment." (Mimeo, at page 57.)

To aid in the development of standard offers incorporating these basic principles, D.82-01-103 provided further definition of the factors to be reflected in the firm capacity payments. This amplification of each factor can be summarized as follows:

1. *Dispatchability.* According to D.82-01-103, dispatchability is achieved in standard offers by

time basing capacity and energy prices and requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies consistent with resource limitations.

2. *Reliability.* Reasonable requirements for reliable operation and availability during utility system peak load periods are to be imposed in the standard offers. These requirements, however, should not be unduly restrictive or complicated or impose standards of reliability greater than the utility plants the QF displaces. When resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure of reliable operation.

3. *Contract duration, termination, and sanctions.* QFs should be provided the option for levelized capacity payments for periods up to 25 to 30 years. Other than general statements requiring fair contract requirements, the exact terms for provisions relating to termination and sanctions were not specified.

4. *Scheduling of outages.* A utility purchasing firm capacity from a QF may reasonably require the QF to schedule maintenance of that generation during periods established by the utility. The utility must provide reasonable periods for QF scheduled maintenance and only re-

quest deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments must not be reduced during scheduled maintenance periods.

5. *Availability during emergencies.* A QF must be expected to operate at maximum capacity on notice to meet utility needs for capacity during emergencies.

Other than our recognition that plant capacity factor, as opposed to availability, might be a better measure of the reliable operation of certain technologies, D.82-01-103 did not endorse any special treatment for specific resources other than small hydro electric facilities. For hydro QFs larger than 100 kW, adjustments for dry year unavailability are to be made in determining the QF's base stream flow and monthly firm capacity rating. A hydro QF would be allowed to use either (1) flow data directly applicable to the QF's facility, when available, or (2) the flow data for the area closest and most similar to the QF's facility, using areas sufficiently limited in size so that the true value of local areas would not be lost or obscured. The minimum June through August flow, from which the monthly firm capacity rating was to be derived, would be based on the five lowest flow years taken from a 50-year minimum continuous record. If this data could not be developed, utilities and QFs would agree upon a shorter time period with fewer minimum flow years averaged into a monthly capacity rating. For both options, capacity values were to be paid in dollars per kW per month and otherwise subject to the requirements of a firm capacity sale.

In examining the utilities' compliance with the OIR 2 decisions, we will first consider the issue relating to all of the above factors, except for termination. A review of the utilities' proposed termination provisions will follow in a separate section.

1. Performance Requirements

A finding of compliance or noncompliance with the requirements of D.82-01-103 enumerated above requires an understanding of each of the utility's standard offer provisions relating to performance. Additionally, the positions of both utilities and interested parties must be considered.

a. PG&E Standard Offer No. 2, Appendix C - Firm Capacity Price Schedule

PG&E's standard offer provisions governing the conditions of firm capacity payments are set forth in Appendix C of its Standard Offer No. 2 (Firm Capacity and Energy Power Purchase Agreement). PG&E's minimum performance requirements are inextricably tied to the type of capacity payment chosen by the QF. These two payment options are described in Section C-5 of appendix C.

Under *Option 1* the monthly payment for capacity, paid in dollars per kW per month, is one-twelfth of the product of the designated per kW annual contract capacity price multiplied by the contract capacity (the amount of energy in kW to be sold and delivered) and by the appropriate loss adjustment factor. In order to receive these 12 equal monthly payments, the QF must meet performance standards which essentially make it dispatchable by PG&E. Specifically, PG&E requires the QF's contract capacity to be available (dispatchable by or delivered to PG&E) during all on-peak hours of the peak months of June, July, and August, subject to a 20% allowance for forced outages in any month. The contract capacity must also be dispatchable throughout the rest of the year subject to a 20% monthly allowance for forced outages and a designated allowance for scheduled maintenance. During these months other than the peak months, the QF may accumulate and apply the 20% forced outage allowance for any consecutive three-month period. Dispatchability is defined by PG&E as the QF being operable and capable of being called upon

at anytime to deliver capacity at any level up to the full contract capacity. The QF must demonstrate that its facility is fueled by a reliable fuel supply and that adequate fuel storage is available to deliver power as requested by PG&E's system dispatcher.

Option 2 provides for payments to QFs, again in dollars per kW per month, for the amount of capacity actually delivered during peak and partial peak hours. A formula for calculating this payment is specified in Option 2 and includes a 20% forced outage allowance credit for each month. Although a QF electing Option 2 must deliver its full contract capacity to PG&E during the peak hours of the peak summer months subject to a 20% forced outage allowance, no other performance requirements are imposed for the rest of the year. During the summer peak months, the 20% forced outage limitation and the measurement of performance according to deliveries means that the QF must deliver the contract capacity at least 80% of the peak hours, thus achieving a peak period capacity factor of 80% during the summer months. During the rest of the year the QF is paid for capacity according to how much energy is delivered, but there is no specified performance level that must be met.

Under Option 1 the QF is dispatchable and has its performance judged according to its *availability* or ability to deliver whereas under Option 2 the QF is not dispatchable and has its performance judged according to its *output* or actual deliveries. Also, under Option 2 performance is only judged during the peak summer months whereas under Option 1 there are certain year-round requirements. Apart from these basic differences the remaining provisions of Appendix C are, for the most part, identical for both options. These provisions include a limitation on contract capacity price used to calculate QF payments under either option of 100% of PG&E's shortage costs.

Additionally, to qualify for firm capacity payments, outages for scheduled maintenance (i) cannot occur within the first six months of operation, (ii) cannot occur between May and October unless otherwise agreed to in writing with PG&E, (iii) cannot be undertaken without six months' prior written notice to PG&E's system dispatcher, and (iv) cannot exceed a total of 35 days in any 12-month period. Both options permit capacity payments to continue during the period allowed for such scheduled maintenance.

Section C-3 of Appendix C governs failures to meet the minimum performance requirements. Essentially, this section applies (i) if an Option 1 QF fails to have at least 80% of its contract capacity available during the peak hours of the peak summer months or the allowable percentage, taking into account properly accumulated allowances for forced outages in other nonpeak months or (ii) if an Option 2 QF fails to deliver at least 80% of its contract capacity during the peak hours of any of the peak months. If the reason for this failure is other than a forced outage or force majeure, PG&E may immediately suspend the payment of capacity charges for a probationary period not to exceed 15 months. If a QF can meet the minimum requirements during the probationary period, PG&E will pay the QF all capacity payments suspended during the probationary period and reinstate regular capacity payments. If a QF cannot meet its minimum requirements during the probationary period, PG&E may derate the contract capacity to either actual or reasonably expected deliveries, with the quantity by which the capacity is reduced being subject to termination provisions. If the failure to meet minimum requirements was caused by a forced outage,[1] the QF will not receive capacity payments for the month in which this circumstance occurred. During a force

[1]PG&E defines forced outage as any outage resulting from a design defect, inadequate construction, operator error, or a breakdown of the mechanical or electric equipment that fully or partially curtails the electrical output of the QF.

majeure, capacity payments will be continued for a period of 90 days following the occurrance.

Finally, PG&E's Appendix C provides no special provisions for any technology other than hydroelectric projects. The only separate provisions for small hydro QFs deal with the determination of the QF's monthly capacity rating. The procedure followed by PG&E mirrors the requirements of D.82-01-103, i.e., with the average dry year being based on the average of the five years of the lowest annual generation as derived from 50-year natural flow data. The small hydro QF is otherwise required to meet the minimum performance requirements for either payment option chosen.

(1) Positions of the Parties

During the hearings and in briefs, both criticism of and support for PG&E's performance requirements were voiced. Generally, IEP, whose views were shared by the State Energy Task Force, found all of the utilities' proposals too rigid and, like the CEC, endorsed statewide performance standards which would be more flexible. IEP asserts that PG&E's offer improperly excludes wind and waste-to-energy facilities by imposing overly strict performance standards during summer peak periods and inflexible scheduled maintenance requirements. Other parties, including CMA, Calcogen, and Kimberly-Clark, however, endorse PG&E's approach which allows performance to be measured by availability as well as energy production. The staff concludes that, with certain modifications, PG&E's Option 1 is a reasonable model for an offer based on availability.

Parties both supporting and disputing PG&E's general approach, however, also had a number of specific recommendations. To begin with, it was urged that payments above 100% of PG&E's shortage costs should be offered to QFs whose performance exceeds the operating standards normally expected of PG&E plants. The staff sug-

gests that payments should be provided up to 125% of PG&E's capacity costs and should be calculated according to a recommended formula for an additional capacity credit. Staff also suggests that PG&E's definition of dispatchability be modified to give the utility the right to require only increases, not decreases, in a QF's operation and to limit dispatchability to on- and mid-peak periods and emergencies.

IEP and other QFs ask that statewide maintenance standards be adopted which would allow (a) hourly use of the alloted time, (b) an additional 45 days or use of accumulated unused days every three years for major overhauls, and (c) notice requirements related to the amount of time to be used (i.e., 24 hours' notice for a maintenance period less than 24 hours, seven days' notice for maintenance in excess of 24 hours, and six months' notice for major overhauls). The special needs of waste-to-energy projects which require 55 days a year for maintenance should be recognized.

IEP and the staff also urge that all capacity payments should not be suspended during PG&E's probationary period. IEP testified during hearing that such an interruption in cash flow could cause a QF to meet its debt service obligations. Both the staff and IEP recommend that during the probationary period the QF be paid for the actual level of capacity performance it can achieve. At the end of the period, payments should be reinstated based on the level of operation which the facility can reliably perform. Staff states that the capacity payments suspended for the capacity actually delivered should include an allowance for forced outages.

Finally, a number of the parties recommend that adjustments be made in PG&E's approach for small hydro and waste-to-energy facilities. Staff concludes that since the contract capacity of a small hydro facility is based on the average of five years low flow during peak months,

such a facility should not be further penalized for failing to meet PG&E's peak availability standard in years when flow is less than the five-dry-year average. Staff recommends that PG&E's performance factor, part of the payment calculation for Option 2 QFs, should be set at 1.0 in establishing the nameplate capacity for small hydro QFs and that the peak availability requirement should be waived. Further, staff urges that termination provisions should not be applied to hydro QFs who fail to deliver the contracted capacity only because of low flow conditions.

For waste-to-energy projects, the staff asks the Commission to consider developing over the next year the proper data and methodology required to base capacity payments to waste-to-energy projects on the combined performance of all such projects during the peak months. The group performance would be compared to a utility's baseload plants and the individual waste-to-energy facility would be paid according to its performance as compared to that of the group.

(2) PG&E's Response

In its brief, PG&E asserts that the provisions of its Appendix C are in full compliance with the OIR 2 decisions. Only to accommodate QF development does PG&E suggest any modification of its approach. In particular, it is PG&E's opinion that no adjustments to its minimum performance requirements are necessary for specific technologies, such as wind or solar, since a QF which cannot meet those requirements is less valuable to the utility than one which can. Further, a QF always has the option of signing an as-available contract which was specifically designed to accommodate resource uncertainty.

With respect to payments above 100% of PG&E's shortage cost for QFs whose performance exceeds utility plant, PG&E argues that such a payment should only be made to QFs that can actually outperform utility combustion turbines and only if they can do so on a consistent basis.

PG&E allows QFs to have a "liberal" 20% peak period forced outage rate under its standard offer but contends that its own peaking units have forced outage rates that are actually less than this amount. Therefore, for QFs to receive payments in excess of the combustion turbine shortage cost proxy, they must outperform this higher standard of the combustion turbine (i.e., a 10% or 15% forced outage rate). Further, they must commit to achieve this performance on a consistent basis.

On the issue of scheduled maintenance, PG&E contends that the standard offer should not become a "lowest common denominator" contract which is stretched to accommodate specific technologies that cannot meet reasonable requirements. For a QF which cannot meet PG&E's requirements, a special agreement or an as-available contract again is always an option. PG&E is willing, however, to allow a QF when it enters the contract either (1) to take only a portion of the allowed number of days per year for scheduled maintenance and combine the remaining days over three years into maintenance periods for major overhauls or (2) arrange an average of 35 days per year over the life of the contract allowing an increasing number of days for maintenance as the project ages.

PG&E is also of the opinion that a probationary period of at least 15 months is necessary to allow PG&E to assess the level of capacity the QF can reliably deliver or make available during the peak months after it has failed to perform. PG&E is willing, however, to redraft its provisions covering the suspension of payments during this period in keeping with the suggestions made by IEP during hearings.

Specifically, PG&E proposed that under Option 1, if a QF fails to meet the minimum performance requirements, it will continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has

not demonstrated an ability to provide its full contract capacity to the utility that capacity would be derated subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced will be subject to termination provisions.

For Option 2 QFs, the same opportunity to earn capacity payments during the probationary period for the amount of capacity actually delivered will be provided. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity will be derated to the lower monthly amount of capacity actually delivered during the peak months. The lost capacity will again be subject to termination provisions.

PG&E does not support staff's position regarding adjustments of PG&E's capacity payment formula for small hydro QFs. According to PG&E, a hydro QF already benefits from the increase in its capacity rating caused by basing that rating on the average of five dry years, rather than the driest year. PG&E does believe, however, that hydro QFs during the "drier" year should have their capacity payments suspended, as opposed to having the contract terminated, as follows:

> "1. Hydro QFs which have their capacity ratings based on the five dry year average should not have their capacity terminated or derated when their failure to meet the minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average.
>
> "2. During 'drier' year conditions, capacity payments to hydro QFs should be suspended. Capacity payments should resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating." (PG&E's concurrent brief, at pages 31-32.)

b. Edison Standard Offer No. 2 Part I, § 13 (General Terms and Conditions - Availability) and Appendix B. 2 (Capacity Payments for Firm Power Purchases)

Unlike PG&E, which offers payments for firm capacity based on availability and energy production, Edison's standard offer provides only one basis of payment for a firm power purchase - the QF's energy production. Basically, under Edison's firm capacity offer, the QF is paid according to its output or capacity factor. In addition, its emergency availability is considered.

The QF's output or capacity factor is taken into account in two ways in the payment provisions included in Appendix B. 2 of Edison' Standard Offer. First, the QF is paid more for achieving a higher capacity factor or a level of kWh output that is a higher percentage of the maximum possible kWh output given the kW contract capacity. At an 80% capacity factor the QF is paid 100% of the per kW capacity price for each kW of contract capacity. At higher capacity factor levels, representing performance in excess of Edison's plants, the price paid per kW is escalated further, up to a maximum of 124% of the basic per kW capacity price for 100% capacity factor performance.

The second way in which output is taken into account is through Edison's "hurdle factor". If a QF output falls below a 50% capacity factor (the "hurdle"), its capacity payment is cut in half for that period. Edison claims that this hurdle factor takes into account QF reliability because QFs that do not perform within a certain range (greater than the hurdle) are less reliable and less valuable.

The "hurdle factor" is the only aspect of Edison's offer that indirectly requires a prespecified level of output. As noted earlier, under PG&E's output-based option, QFs must meet an 80% summer peak output requirement or face probation and termination of all or part of their contract

capacity. Here, QFs must meet a 50% output level in any month (not just peak summer months) or their payments are reduced. Under the Edison scheme, termination penalties would not apply.

Edison's offer also has an emergency availability requirement. Emergency availability is defined in Section 13.2 as follows:

> "At Edison's request seller shall, within 30 minutes of such request, make all reasonable effort to deliver power at an average rate of delivery at least equal to the (contract) capacity . . . during periods of emergency."

If the QF Seller fails to respond, its capacity payments are reduced by one-half for the six months following the request "until Seller demonstrates (the) ability to deliver full capacity pursuant to Section 13, Part I, or until Seller responds to a subsequent request for full capacity, in which case the six-month capacity payment reduction shall be waived for the remaining reduced payment monthly billing periods." In all cases, however, the reduced payment will apply to the month in which the Seller fails to respond to a capacity request.

In addition to these requirements contained in Appendix B. 2, Section 13 also provides that a QF which fails to respond to an emergency when first requested by Edison will not have its capacity payments reduced. However, after this initial request, whether complied with or not, any subsequent failure by the QF to comply with a request by Edison will result in the aforementioned 50% reduction of capacity payments specified in Appendix B. 2. Failure to comply with a request during an existing six-month reduced capacity payment period will extend that period to six months following the latest failure.

Edison contends that its "availability factor" provides a specific way of valuing QF emergency availability, one

of the factors that required by D.82-01-103 to be reflected in the firm capacity payment. The availability criterion is somewhat analogous to the availability required under PG&E's dispatchability option (Option 1) except that there is no allowance for forced outages as in the PG&E's example, and under the Edison's offer the requirement is a part of an output or capacity factor-based payment scheme.

Edison's payment formula also reflects adjustments for scheduled maintenance. Specifically, Edison allows a maximum of 480 hours (20 days) per year for scheduled maintenance and an additional 1,080 consecutive hours (45 days) once every three years for major overhauls. In Part I, Section 8.4, of its offer, Edison defines reasonable advance notice of scheduled outages, including any reduction in capacity availability as 24 hours for an outage of less than one day, one week for an outage of one day or more, and six months for major overhauls. The off-peak hours are to be used for scheduled and routine maintenance and the QF is required to make reasonable efforts to limit its outages during on-peak and mid-peak periods.

(1) Positions of the Parties

Many of the parties found the same general shortcomings in Edison's offer as PG&E's. For example, QFs complain that here, as in the case of PG&E, many performance requirements are rigid, "all or nothing" type requirements that do not adequately reward partial performance.

In addition, a number of specific criticisms of Edison's offer were raised. In particular, several QFs complain that Edison has failed to make an offer based on availability similar to PG&E's. Staff agrees that Edison should have an availability option. In staff's view, a forced outage rate is the proper performance criterion under such an option. Staff also contends that this availability option should reflect, as Edison's current "output" offer does, a higher payment for operation better than Edison's plants.

QFs note that whereas PG&E's performance requirements would appear to exclude technologies that cannot be dispatchable (Option 1) or meet an 80% summer peak output requirement (Option 2), Edison's offer would not exclude any technologies. In other words, under Edison's offer, there would be no lower limit or absolute eligibility for the firm capacity contract, as even QFs that cannot meet the availability and hurdle factors would receive some capacity payment, however small. Still, many parties object to the hurdle and availability factors as being too rigid and harsh. The deletion or adjustment of these factors is recommended, particularly for certain technologies.

Staff observes that Edison's own plants would have difficulty meeting a 30-minute response time required by Edison for QF emergency availability. Instead, staff argues that Edison should only require that a QF make reasonable efforts to respond to an emergency as soon as feasible consistent with its capabilities. CMA also agrees that technical feasibility is the proper criterion for meeting any emergency and argues that lack of emergency availability should not have such a major impact on capacity payments since it represents only a small fraction of a utility's total avoided costs. IEP suggests that the availability factor should not be applied to a QF on full or partial forced outage which has notified Edison in advance.

IEP recommends that a sliding scale be used in applying the hurdle factor rather than a single 50% capacity factor cutoff. IEP contends that this sliding scale will better reflect the actual level of capacity the QF is contributing to the system. The State Energy Task Force voices the concern that neither the hurdle factor nor the availability factor is applied to Edison's own plants and that these factors require QFs to meet a stricter performance test than utility plants.

If the availability and hurdle factors are to be adopted as proposed by Edison, several of the parties urge that

the availability factor be waived for solar (both solar-thermal and solar-photovoltaic) and wind technologies, with wind's nameplate capacity being derated by 20%. For reasons similar to its suggested modifications of PG&E's offer for small hydro, staff recommends that Edison's period capacity, hurdle, and availability factors be set at 1.0 for hydro QF's whose capacity rating is based on the average of the five lowest flow years. For waste-to-energy projects, IEP and the California Waste Management Board ask that these QFs be given a longer time to respond to an emergency consistent with the technology (eight hours) and that the calculation of their capacity payment not include the hurdle factor.

Most parties endorsed Edison's basic approach to the allowed time and notice for scheduled maintenance. IEP, for instance, recommends Edison's offer as a model for statewide scheduled maintenance standards. IEP would only modify Edison's language by increasing the yearly allowance for scheduled maintenance to 35 days. For waste-to-energy projects, the California Solid Waste Waste Management Board again recommends a yearly allowance of 55 days.

(2) Edison's Response

Like PG&E, Edison believes that its performance criteria for firm capacity payments fully comply with the OIR 2 decisions. In particular, Edison asserts that both its availability and hurdle factors are reasonable. Edison argues that QFs that cannot consistently achieve a capacity factor above its 50% "hurdle" are less reliable and less valuable and they should, therefore, have their capacity payment reduced as Edison does in its standard offer. Similarly, Edison believes that a QF which is not available during emergencies is less valuable and that this situation also warrants reduced capacity payments.

Edison argues that the emergency availability requirements is appropriate even if Edison does not impose a

similar requirement on its own plants and its plants and the QF plant are treated differently. Edison contends that it is appropriate to treat the two differently since they have different obligations. The utility, by virtue of its retail franchise, has an obligation to serve customers at all times whereas the QF has no incentive beyond price to serve Edison's ratepayers during emergencies. Edison contends that the 30-minute response time that it requires for QF emergency availability is reasonable and that any adjustments should only be considered on a case-by-case basis.

Edison does offer to modify the application of its hurdle and availability factors for specific technologies. In particular, Edison has adopted the adjustments suggested by the staff for wind, solar, and hydro with the exception of retaining the period capacity factor for small hydro to permit the capacity payment to be based on actual performance.

Edison also states that it is willing to pay QFs in dollars per kW per month based on availability, but only if the QF is fully dispatchable and is as reliable as Edison's generating resources. According to Edison this dispatchability and reliability will require (1) an accurate measurement of QF availability during each time period for each season; (2) detailed, accurate, and verifiable QFs records with periodic company review to determine a QF's actual energy production; (3) a QF being the functional equivalent of an Edison combustion turbine or the purchased power used by Edison to develop its shortage costs; (4) a QF's performance being measured individually and not in the aggregate; and (5) full dispatchability permitting the utility to increase and decrease generation. As in the case of PG&E, staff disagrees with this view of dispatchability and recommends that Edison should not have sole discretion over a QF's operation and should be allowed only to require increases in a QF's production or availability.

In recognition of the wide variation of QF's scheduled maintenance requirements, Edison endorses modification of its standard offer to allow more flexibility in scheduled maintenance allowances. Specifically, Edison will provide 35 days of scheduled maintenance per year and a year-to-year accrual of unused maintenance days, not to exceed 45 days.

c. SDG&E Standard Offer for Firm Capacity, Section 6 (Purchase Price of Energy and Capacity) and Exhibit C (Capacity Payment Schedule for Firm Capacity QFs)

SDG&E offers two payment options to QFs signing its firm capacity contract. Both options, set forth in Exhibit C of the offer, are based on energy production, as opposed to availability, and the choice of capacity payment option is limited by the payment option selected for the QF's sale of energy to SDG&E. If a QF elects energy Option 1 (as-available energy), it will be paid for capacity only according to capacity Option 1. A QF choosing energy Option 2 (five-year forecast) can be paid for capacity under either capacity Options 1 or 2. The two options for capacity payments are based on two different performance criteria which must be met for payment.

Under Option 1, capacity payments are made on the basis of the QF's output or energy actually delivered. A QF starts with a certain levelized annual capacity price in dollars per kW which varies depending on the length of the contract that the QF signs and the year its operations start. This annual price is spread to different hours within the year based on a "supply factor", an allocation factor that values capacity more during seasonal or daily peak demand hours. The resulting ¢/kWh capacity prices for different time periods are paid to the QF for all the kWh energy output that it provides in each time period. There are no prespecified output or availability performance levels that must be met. There are no conditions to or limitations on scheduled maintenance.

Option 2 is entitled Payment by Capacity ($/KW-month). Under this option, payment is based on output or capacity factor and requires that certain peak period performance standards be met. The Option 2 monthly capacity payment equals the product of the Equivalent Capacity Factor (ECF) and the appropriate $/kW number in the capacity table again determined by the length of the contract and the QF's operation date. The ECF is calculated as follows:

$$ECF = \frac{QxA}{Cx(H-S)xR}$$

Under this formula, Q represents the delivered energy in kWh during monthly on-peak and semi-peak time periods; A is a monthly capacity allocation factor differentiated by season; C is the contract capacity; H stands for the total monthly on-peak and semi-peak hours; S is a QF's monthly scheduled maintenance during on-peak and semi-peak hours, which is not to exceed 75% of H; and R is the reliability of SDG&E's system alternative capacity source. R currently has a value of 0.85.[2]

To be paid under this formula, a QF must (a) deliver enough output during peak and semi-peak hours of the month so that the monthly ECF is greater than 0.5 and (b) schedule outages at least six months in advance during periods acceptable to SDG&E. Scheduled outages must not exceed 720 hours (30 days) in any 12-month period. Agreed dates for scheduled maintenance cannot be changed without notice.

If the QF fails to meet the minimum performance provisions set forth in Exhibit C, SDG&E will immediately suspend or reduce the capacity payments to the QF for a probationary period. The terms and conditions of this suspension, set forth in Section 16.5 of the standard offer, are similar to those in PG&E's standard offer, except that

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[2]SDG&E bases this 85% reliability on its own peaking plants, which is asserts have, at most, a 15% outage rate.

the probationary period is not to exceed 14, as opposed to 15, months.

(1) Positions of the Parties

Unlike their response to the offers of the other utilities, a number of QFs, generally represented by IEP, endorse SDG&E's approach and urge its adoption for both PG&E and Edison.[3] IEP believes that SDG&E's two-option contract will appeal to a wide variety of QFs. In IEP's opinion, SDG&E's Option 1 correctly recognizes the valuable contribution which a QF can make to the utility system just by signing a long-term commitment. Although a QF could achieve a higher payment agreeing to the more stringent requirements of Option 2, a QF who agrees to Option 1 will receive a payment 15% below that of an Option 2 simply by making a long-term commitment.[4]

Other parties however, did find deficiencies in SDG&E's offer. Among other things several parties pointed out that SDG&E does not have an option (such as PG&E's) which values QF's performance based on availability rather than energy production. Further, it was claimed that SDG&E does not allow payment above the 100% shortage cost level for QFs that exceed the performance of utility plant. Staff contends that under Option 1 ¢/kWh payments, a QF that achieves a 100% capacity factor, a performance level better than utility plants, will only receive 100% of the combustion turbine capital cost proxy, not some higher level. Staff would have the Option 1 QF receive 100% of the shortage cost proxy for 80% capacity factor output and 125% for 100% output. Similarly, under Option 2, staff

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[3]IEP specifically suggests that PG&E's and Edison's offers would be acceptable if an option like SDG&E's Option 1 were also part of these offers.

[4]QFs under Option 1 receive 100% of the $/kW annual capacity price for a 100% capacity factor during the year, while QFs under Option 2, by virtue of the "R" in the formula listed above, receive 100% of the $/kW annual capacity price for an 85% capacity factor performance.

would have the QF receive 100% of the capacity price for an 80% capacity factor, rather than 85% as now specified by the reliability factor, R. Use of the 80% standard by staff is based on their estimate of the average reliability of SDG&E's plants or its system as a whole.

None of the parties suggested any adjustments to SDG&E's payment option or performance requirements for specific technologies. Comments regarding PG&E's suspension of payment provisions and scheduled maintenance allowance were equally applicable to SDG&E.

(2) SDG&E's Response

SDG&E is willing to modify its firm capacity offer so that the choice of capacity option will not be limited by the type of energy payment chosen. However, SDG&E concludes that both its Options 1 and 2 are reasonable and consistent with OIR 2. According to SDG&E, Option 1 reflects an aggregate value of firm capacity and is intended for QFs which are unable or do not desire to guarantee a minimum degree of availability. Under these circumstances, Option 1 will be a useful tool in making the standard offers widely applicable to QFs. SDG&E acknowledges, however, that the factors recited in D.82-01-103 for inclusion in a payment for firm capacity are actually contained in its capacity payment Option 2.

With respect to Option 2, SDG&E does not believe it is necessary to have an availability option under which the QF is dispatchable. SDG&E concludes that it would be impossible to measure availability when it is not based on actual output, but is based on a measure of forced outages and the potential to produce output. Further, SDG&E argues that its Option 2 actually reflects availability since it requires QFs to produce a certain amount during peak and semi peak hours. SDG&E's minimum ECF of 0.5 under Option 2 is a standard of peak period reliability and availability.

SDG&E disagrees with staff's contention about payments above 100% of the shortage cost. For Option 1 type QFs, SDG&E argues that they are less reliable and therefore should only receive a maximum of 100% of the shortage cost for 100% capacity factor output (similar to the as-available capacity payment). For Option 2 QFs, SDG&E argues that payments above 100% *are* allowed for capacity factor performance above 85%. This 85% standard is based on a conservative assumption of its combustion turbine plants' reliability. SDG&E disagrees with staff's use of an 80% standard as it incorrectly is based on system reliability rather than peak or plant reliability. Use of the latter standard is appropriate in order to be consistent with the shortage cost proxy approach.

SDG&E offers no changes to its provisions governing suspension of payments or scheduled maintenance. SDG&E observes that its scheduled maintenance allowance is already sufficiently flexible, particularly since restrictions on maintenance only apply during peak and semi-peak periods.

d. Discussion

In D.82-10-103 the utilities were directed to draft a firm capacity contract, designed for QFs that could meet certain operating standards, and an as-available capacity contract, designed for QFs that could not, or did not desire to, meet such standards. The operating or performance standard envisioned in D.82-01-103 for firm capacity QFs was to be a standard which required QF availability during system peak periods. The standard was to designed to reflect aspects of peak period availability such as dispatchability, reliability, availability during emergencies, scheduling of outages, and contract duration, termination, and sanctions. QFs that signed contracts as firm power sources were to meet this specified standard of performance.

We have before us three general types of performance standards in the utilities' filings. The first is a performance standard based on a level of peak period availability, as

exhibited by PG&E's Option 1. The second is a performance standard based on a level of peak period *output,* as exhibited by PG&E's Option 2, SDG&E's Option 2, and Edison's single payment offer. The third is a performance standard that requires only a commitment to a certain contract length with no specific peak period output or availability. This approach is embodied in SDG&E's Option 1.

We find that PG&E's Option 1 availability standard, with the modifications discussed below, is in compliance with the requirements of D.82-01-103. Indeed, as the requirements of D.82-01-103 are oriented towards QF peak period availability, this availability type of standard most clearly follows from this decision. Under this option the QF is dispatchable and available for emergencies. Moreover, because of the limitations on peak periods forced outages, peak period reliability is assured. Nonperformance is deterred by the application of termination provisions. Requirements are made for scheduled maintenance.

All three utilities have proposed a performance standard that is based on a QF achieving a certain level of peak period output. D.82-01-103 specifically allows for a performance option based on capacity factor or output rather than availability. Output requirements are an indirect way to assure availability for nondispatchable units.

We consider PG&E's Option 2 with the modifications discussed below, to be in compliance with D.82-01-103. Under this option the QF must deliver its contract capacity to PG&E at least 80% of the time during the peak hours of the peak summer months. During other periods there are no specified performance requirements, other than scheduled maintenance limitations.

Turning to the aspects of peak period availability recited in D.82-01-103, it is clear that the peak period output requirement in PG&E's Option 2 assures reliable operation during the hours of the year when reliability is most im-

portant. The QF under Option 2 is not dispatchable, but the peak period output requirement and the general weighing of capacity prices toward peak and semi-peak hours assures that QFs will operate during most, if not all, of the same periods as they would have had they been under the dispatcher's control. D.82-01-103 specifically allows for nondispatchable QFs to be accommodated in the firm standard offer. Time-of-use pricing and peak period output requirements under Option 2 will also assure that QFs will be delivering their capacity during the most likely emergency periods. Finally, maintenance scheduling and termination provisions apply as they do in the case of PG&E's Option 1.

The essential requirement of performance under both PG&E's Option 1 and 2 is the 80% summer peak hour availability or output requirement. IEP has argued that this standard is too stringent and one that many utility plants could not meet. We consider the standard to be reasonable for QFs that sign up as firm sources and receive capacity payments based on the combustion turbine. Evidence in this proceeding, with which IEP concurred, indicated that utility peaking plants, such as combustion turbines, have an average peak period availability of greater than 80%.

We do agree with IEP that PG&E's options are too stringent in other ways, such as its requirements for scheduled maintenance. As discussed below, we will require certain changes with respect to this and other performance requirements.

IEP also argues that an 80% peak availability or output requirement is too flexible and is of an "all or nothing" nature. We disagree. Under the reduction in payment provisions which PG&E proposed in its brief, discussed below, a QF that does not achieve the 80% availability or output standard will still receive a payment commensurate with its actual production and will have the opportunity to have

its original capacity payments reinstated if its availability or output reaches the 80% level during the probationary period.

The flexibility of the standard is also enhanced because it may, if need be, only apply to part of the QF's total capacity. In other words, if a 10 MW QF facility produces consistently at a 5 MW level and sporadically at higher levels, the QF can sign up for 5 MW of firm capacity (which meets the 80% standard) and sell the rest of its output on an as-available basis.

SDG&E's Option 2 is like PG&E's Option 2, based on the QF's output. In certain cases, however, this option imposes a more lenient performance standard than PG&E's by requiring only a 50% output level which the QF may fail to meet and still not be exposed to termination or probation provisions. On the other hand, the 50% standard applies to peak and semi-peak hours during all months of the year, not just summer month peak hours. Partial capacity payments are also not allowed for performance that is somewhat below the standard. If the 50% level is not met, the QF receives no payment for that month.

We do not find SDG&E's Option 2 to be in compliance with D.82-01-103. The 50% standard is, in our view, not an adequate level of peak availability and reliability, even if it does apply to more hours of the year. The firm capacity performance standard should be oriented toward the system peak hours when reliability is of greatest concern. It should be a level of reliability that is commensurate with the utility plant that is avoided by QF purchases. Utility plant has a higher level of peak period availability than 50%. Also, it is more reasonable, in our view, to allow more flexibility than SDG&E allows by giving partial payment, rather than zero payment, for performance below the standard. Further, SDG&E's zero payment for nonperformance does not differentiate between temporary and repeated nonperformance. More flexibility should be al-

lowed for temporary nonperformance with termination provisions applied only to continued performance.

We also find that Edison's output-based performance standard is not in compliance with D.82-01-103. Edison's basic performance standard is a 50% output level, incorporated in its "hurdle" factor. In Edison's offer this standard applies to all periods - peak, mid-peak, and off-peak - in all months of the year. Failure to meet this standard results in a 50% reduction in the capacity payment. Edison also requires emergency availability. Failure to meet this standard results in an additional 50% reduction in the payment.

Edison's performance standards do not adequately focus on peak period availability as required by D.82-01-103. Apart from the emergency availability requirement, there is little differentiation between required peak and off-peak performance. The 50% output level is also too lenient for the peak period. On the other hand, the emergency availability requirement is too stringent and places too much emphasis on one aspect of peak period availability. It is for these reasons that we find that Edison's performance requirements for firm capacity QFs do not comply with D.82-01-103.

The final type of performance standard that we must consider is SDG&E's Option 1. This option appears to be a hybrid of the standard offers approved in OIR 2, an offer which could lead essentially to a long-term as-available capacity contract. Although a QF electing SDG&E's Option 1 would be committing its resource for a specified period of time at a price which would vary by time of energy delivery, the QF would not be required either to be available during peak periods and emergencies or to match the reliability of SDG&E's own plants. We understand the reasons many QFs have found such an option desirable, i.e., the opportunity to have payments which would be levelized and possibly greater than those paid

an as-available producer. Nevertheless, Option 1, failing to reflect the required performance standards, is not an option to purchase firm capacity as defined in D.82-01-103. While we might consider such a hybrid in the future, it was neither contemplated by nor in compliance with that decision.

Because of our conclusions, it will be necessary for the utilities to refile their standard offers in conformance with this order. Although we believe that PG&E's Options 1 and 2 can serve as appropriate models for firm capacity standard offers based on availability and energy production, even these offers require modification. Neither SDG&E nor Edison will have complied with the OIR 2 decisions until each offers payment options based on a QF's availability and energy production equivalent to those offered by PG&E, as modified herein.

To achieve overall compliance with this decision and OIR 2, the following principles should be incorporated in the utilities' firm capacity standard offers.

(1) Dispatchability

We concur with the staff that the definition of dispatchability used in PG&E's Option 1 and any other offer based on availability should give the utility the right to require only increases, not decreases, in a QF's operation. At this time the language employed by PG&E (required capacity deliveries "at any level up to the full contract capacity") is ambiguous, but appears to permit both upward and downward dispatchability. We agree with the staff that the ability of a utility to interfere with a QF's operations in such a manner is unwarranted and unreasonable. The utility should not be in a position to unilaterally jeopardize a QF's operation and in turn reduce its payments. Regarding dispatchability, D.82-01-103 only required that a QF be sufficiently dispatchable to be available for a utility's *increased* needs during peak periods and emergencies. For

these reasons, we also find Edison's approach to dispatchability too restrictive.

We do not believe it is necessary, however, to define dispatchability as limited to on- and mid-peak periods and emergencies if an approach like PG&E's is used. Such a limitation is both implicit and explicit in PG&E's Option 1. For the peak months, a QF signing Option 1 is required to have 80% of its capacity available only during the peak hours and for the remainder of the year need only maintain a somewhat flexible forced outage rate. Because PG&E offers no method for checking on a QF's ability to respond in every hour of each day, but rather uses an on-call approach, a QF will at least have the minimum ability to respond consistently to system emergencies which cannot be predicted.

While we could adopt Edison's response time (30 minutes) criterion for emergencies, we believe that the record in this proceeding is not sufficient to designate a specific response time for all utilities and that PG&E's requirements essentially accomplish this same result by ensuring a QF's readiness to perform. The only time PG&E would possibly need to increase a QF's supply is at times when its own demand increases (i.e., peak, semi-peak, and emergencies). PG&E's approach allows a QF to meet all of these performance factors without placing an unreasonable burden on a QF's operation or one inconsistent with PG&E's plant operations.

(2) Payments in Excess of a Utility's Capacity Costs

We conclude that an option is not in compliance with D.82-01-103 or this order unless it provides for payments in excess of a utility's capacity costs to QFs whose performance exceeds that of the utility's plants. We do not believe that a firm capacity QF must be the exact functional equivalent of a utility's peaking combustion turbine to receive an offer based on 100% of a utility's capacity costs. However, we do agree with PG&E that to receive

higher payments the QF's consistent level of performance should exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. Such a requirement will ensure that the utility will not pay more than its avoided costs, the previously determined level of payment found reasonable for QF purchases.

Testimony during hearing indicated that the availability factor of a combustion turbine could range from 80% to 94%. To receive higher payments, a QF should at least meet a comparable level of performance during the utility's peak periods. We believe that it is reasonable, therefore, to require that a QF achieve a peak period availability or capacity factor in excess of 85% before receiving capacity payments in excess of 100% of the shortage cost proxy. Thus, a utility's payment options should include an offer to pay a price higher than the utility's stated capacity costs for those QFs (1) who demonstrate an availability of 85% or better during time periods similar to those specified in PG&E's Option 1 or (2) who deliver capacity during the peak periods at a capacity factor of 85% or better under an output option like PG&E's Option 2. Under these circumstances, a QF who performs at this higher level could receive up to 118% of a utility's shortage cost.

We believe, however, that an additional requirement should be imposed in an availability option which permits the higher payment. PG&E currently intends under its Option 1 to measure a QF's dispatchability by placing the QF "on-call". We believe that a more certain measure of the QF's dispatchability should be required if a QF is to receive payments above a utility's avoided costs in order to ensure whether and at what level the QF actually exceeds utility plant operations. Such a demonstration is therefore required not only to justify the higher payment, but to determine the appropriate level of that payment.

For this reason, we will direct the utilities to include in their standard offers a reasonable method of determining the QF's consistent ability to be available at a forced outage rate of 15% or less. Although SDG&E argues that more operating experience is required to determine a QF's forced outage rate, it is our view that having set the standard (performance at an availability factor of 85% or better) the utility can devise methods to review the QF's actual performance. It is *only* in this case of higher payments that Edison's reporting requirements which it felt were necessary for a QF to be dispatchable might be appropriate.

(3) Adjustments for Specific Technologies

Edison proposed certain adjustments in its firm capacity performance standards for solar and wind technologies. Basically, Edison is willing to waive its emergency availability standards for both technologies and waive the 50% "hurdle" or output standard for wind. Under these circumstances, the capacity payment for wind would be reduced by 20% while the solar payment would be unaltered. As we have not found Edison's performance standard to be in compliance with D.82-01-103, these modifications are essentially no longer at issue. As discussed earlier, we believe that the performance standard that we have adopted, modeled after that proposed by PG&E, offers sufficient flexibility for QFs that can meet a specified level of performance. QFs which cannot meet the specified level of performance can sign an as-available capacity contract or enter into negotiations for a nonstandard contract.

D.82-01-103 did provide a special capacity price adjustment, however, for small hydro facilities. We do find that some clarification of this adjustment is required.

Basically, we have concluded that the position taken by PG&E in response to this issue, recited *supra*, is reasonable with one exception. In its brief PG&E has suggested altering its contract provisions governing the suspension

of payments for failure to meet its minimum performance requirements. Instead of suspending all payments, PG&E will modify its offer to specifically permit payment for the capacity actually delivered during the probationary period. Because we intend to adopt this approach, we believe it is consistent to permit hydro QFs operating during the "drier" year to be paid for the amount of capacity, if any, actually delivered to the utility during this "drier" year period. Capacity payments would resume at the contract price, with no retroactive payments, when hydro conditions once again reach the level used to determine the capacity rating. With this modification PG&E's recommendation should be included in every utility's firm capacity standard offer for hydro QFs whose payments are based on the five dry year average.

(4) Scheduled Maintenance

As in the case of availability requirements, we believe that scheduled maintenance requirements in the firm capacity offer should be reasonably consistent between utilities. We agree with PG&E that our standards for firm capacity should not be formulated based on the "lowest common denominator" and should not jeopardize avoided cost value. However, we also conclude that scheduled maintenance standards should be sufficiently flexible to permit various types of QF operation. Essential elements of any scheduled maintenance allowance should be (1) a reasonable allotment of days for both routine maintenance and major overhauls, (2) sufficient notice to aid utility system planning, and (3) appropriate timing to avoid periods of greatest demand on the utility system.

We believe that these basic principles are embodied in Edison's approach to scheduled maintenance with certain modifications. Therefore, an offer which complies with this decision and OIR 2 must allow the following:

a. Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-

month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis.

b. A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls.

c. Reasonable advance notice to the utility of a scheduled outage will be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for a major overhaul), and six months for a major overhaul.

d. Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months should also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months.

e. No restrictions should be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months).

(5) Reduction of Monthly Payments

For payment options based on either availability or energy production, we generally adopt PG&E's altered approach for reducing payments following a failure to meet the utility's minimum performance requirements. PG&E's original proposal provided that such a failure would result in a total suspension of capacity payments for up to 15 months. Its modified approach, however, would permit payments for capacity actually delivered during the probationary period with the potential of the original payment

level being reinstated or the QF's capacity derated at the end of that time depending on the QF's performance during the peak months. If the QF is unable to deliver its promised firm capacity, the utility should have the ability, as suggested by PG&E, to make that determination over a reasonable period of time. Given the peak month periods of all three utilities, a probationary period of 15 months is reasonable.

Within that time, however, the QF should not experience a total cessation of cash flow if it has a capacity contribution to make to the utility's system. The complete suspension of monthly payments when this circumstance exists is an unreasonably harsh penalty to impose on a Qf whose failure to perform may have resulted from its level of operation during a single peak month. To permit the QF to continue to be paid for capacity actually delivered during the probationary period is a necessary and reasonable part of a more flexible performance requirement.

We agree with PG&E that the QF's ability to meet the minimum performance requirements in peak months following its failure should be used to determine whether its original capacity payment will be reinstated or its contract capacity derated. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. We also adopt staff's recommendation that for the capacity actually delivered during the probationary period an allowance or credit for forced outages at the level otherwise specified in the agreement should be included. In using this approach, no retroactive payment at the end of probation is necessary.

(6) As Available Capacity Payments Prior to Firm Capacity Delivery

During hearing one additional recommendation was made by IEP witness Philip M. Huyck, which although not strictly a compliance issue, does relate to the performance required under a firm capacity contract. It was Huyck's

suggestion that a QF under a firm capacity contract who produce energy during start-up periods before the facility is ready to begin delivery of firm capacity should receive an as-available capacity payment up to the time that its firm capacity operations commence.

Although PG&E and Edison agree in general principle with this proposal, staff asserts that the theoretical basis which supports a payment for as-available capacity does not exist for such a payment during a start-up period. Because of the generally short period involved for start-up and the fact that a utility would probably not have a large number of generating plants in start-up at the same time, there can be no aggregation of energy, as in the case of as-available capacity, to serve as the basis for the utility avoiding capacity costs. Staff suggests that under these circumstances only as-available *energy* payments should be allowed.

After reviewing IEP's recommendation, we find SDG&E's response to this issue to be the most appropriate. Specifically, SDG&E states at page 21 of its concurrent brief:

> "...If a QF has declared an Operation Date, which is defined to be the date the plant is deemed to be capable of reliable delivery of energy and capacity..., the QF will be expected to provide capacity from that date. If the QF is unprepared to deliver capacity at the Operation Date, a different date should be chosen. If the QF anticipates there will be start-up problems, but believes it is entitled to receive some capacity payments, SDG&E suggests that the QF execute an as-available contract of short duration to cover the period in which the QF anticipates start-up difficulties. When the QF is confident that it can provide firm capacity, [it] can commence performance under a firm capacity contract."

By adopting this approach, no additional provisions will be required in the firm capacity contract which might be in conflict with the basis of that offer or, as pointed out by the staff, the theory of an as-available capacity offer. SDG&E's suggestion illustrates the existing options available to a QF under the offers we have already approved.

2. Termination Provisions

While D.82-01-103 included contract termination as a factor to be reflected in firm capacity offers and payments, the decision set forth no specific guidelines governing such provisions. The utilities have properly responded to OIR 2 by including termination provisions in each of their firm capacity standard offers. Within these provisions are liquidated damage clauses intended to reimburse the utility for unearned capacity payments made to QFs and, in some cases, the utility's costs of replacing the lost capacity. Certain of the offers place a value on, and in turn propose a reduction in the damage amount for, advance notice of termination.

In addition to issues related to the damage clauses of the utilities' standard offers, some of the QFs questioned the application of termination provisions to a conversion from a simultaneous purchase and sale of energy to a sale of surplus only. The proposals of the utilities and the views of the other parties on each issue are summarized below followed by our resolution of the issue.

a. Damage Clauses

(1) PG&E - Standard Offer No. 2, Appendix D

PG&E's standard offer for firm capacity distinguishes between two types of termination: termination with prescribed notice (Appendix D, Section D-2) and termination without prescribed notice (Appendix D, Section D-3). The length of the prescribed notice is directly related to the amount of the contract capacity being terminated or re-

duced. This notice ranges from three months for 1,000 kW or less to 60 months for over 100,000 kW.

In the event the prescribed notice is given, the QF terminating its contract is only required to refund to PG&E an amount equal to the difference between the capacity payments already paid by PG&E and the total capacity payments which PG&E would have paid based on the period of the QF's actual performance. This approach is adopted to effect a repayment of overpayments in the early contract years that arise from levelization of the capacity price. Interest is to be paid on the refund at the prime rate as published by the Bank of America. For the amount of capacity terminated, the QF will receive, from the date of notice to the date of actual termination, capacity payments based on the capacity price adjusted to the period of the QF's actual performance.

For termination without prescribed notice, a QF is required to make the refund described above, as well as the following additional payment:

> "Seller shall pay PGandE a one-time payment equal to the amount of contract capacity being terminated times the difference between the current capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given, if any, by multiplying by one minus the ratio of the actual number (as set forth in paragraph D-2). In the event that the current firm capacity price is less than the contract capacity price, no payment under this paragraph D-3 shall be due either Party." (Section D-3.)

In support of its termination provisions, PG&E points out that the levelized capacity payments made under a firm capacity contract provide a steady revenue stream to the QF with a greater portion of the contract income being

received in the early years. Without full contract performance, overpayments should be recaptured to ensure that the QF is only paid based on the costs the utility actually avoided from the QF's operation. In PG&E's view, interest on this refund is reasonable in recognition of the time value of money.

PG&E also believes that its method of calculating damages for termination without adequate notice is consistent with the principles of contract law. Specifically, PG&E contends that it has used an established measure of damages: the difference between the contract price and the replacement cost. According to PG&E, the presence of this provision also serves to encourage QFs to give adequate notice of termination, while limiting the damages caused by a QF to one year's worth of the replacement cost differential.

(2) Edison - Standard Offer No. 2, Part I, Section 5

Under Edison's standard offer, a QF terminating the agreement is required to reimburse Edison for unearned capacity payments according to the following formula: (1-X/N) times the total value of capacity payments paid to date of termination, where "X" is the number of completed years of service from the initial firm capacity delivery date and "N" is the firm contract length. No specific formula is designated for damages associated with Edison's replacement costs. Edison also requires a QF to provide evidence, "to Edison's satisfaction," of its ability to make potential termination payments.

Edison defends its approach, which places no value on advance notice, as requiring the contracting parties to live up to their obligations unless uncontrollable forces intervene. Edison is critical of contract provisions permitting a QF to "buy out" the remaining term of its contract, i.e., PG&E's proposal, since such provisions will encourage QFs to ignore their obligations. According to Edison,

whenever a QF terminates, even with notice, the utility and its ratepayers are damaged at least to some extent by the utility having delayed or eliminated construction because of a QF's availability.

(3) SDG&E - Firm Capacity Standard Offer, Section 16

SDG&E's firm capacity standard offer includes termination provisions similar to PG&E's contract. A distinction is made between a QF terminating with prescribed notice, for which the basis for reimbursement is specified (Termination Payment A, Section 16.2) and termination without prescribed notice, for which an additional one-time payment is required (Termination Payment B, Section 16.4). The major differences between the two utilities are SDG&E's notice periods (ranging from 12 months for 5,000 kW to 60 months for 20,000 kW or more), its adopted interest rate (simple interest of 12% per year), and its calculation of replacement damages. With respect to the latter difference, Termination Payment B is the sum of Termination Payment A and a one-time payment calculated by taking an adjusted capacity price, based on the QF's actual performance, and inflating that figure by 1% per month for the period of the QF's performance. This figure minus the original firm capacity price is then multiplied by the number of kWs terminated by the QF.

SDG&E supports its approach on grounds similar to those urged by PG&E. SDG&E also points out that adequate notice has a value since it permits the utility sufficient time to purchase or construct additional capacity. SDG&E does note, however, that only to enhance certainty in the contract terms did it adopt a simple interest rate of 12% per annum. Further, in SDG&E's view, while its method for calculating its one-time Termination Payment B is reasonable, its complexity might require a different approach, preferably that suggested by the staff below.

(4) Staff

The staff's proposed termination provisions are designed to reflect the principles that (a) standard offers should specify the consequences of a QF's termination; (b) termination provisions should encourage QFs to fulfill their contracts, but also encourage the QF to provide sufficient notice to allow a utility to replace the lost capacity; and (c) damages for termination should be calculated to make the utility and ratepayer whole. Guided by these principles, the staff adopts an approach that is somewhat similar to those proposed by PG&E and SDG&E.

Specifically, the staff endorses the distinction between QFs which provide adequate notice and those which do not. Staff adopts the notice periods proposed by SDG&E and the general concept of the recovery of overpayments with interest calculated at the prime rate as determined by a common reference source. According to the staff, however, the additional payment required of a QF which fails to give the minimum notice should equal 50% of the amount of the capacity overpayment calculated without accrued interest. The full "penalty" should be reduced in direct proportion to the length of notice the QF gives as compared to the prescribed notice period. Staff argues that the penalty should be based on a number that is known at the time the contract is signed, not an uncertain future capacity replacement cost figure. Staff therefore bases the additional payment required of QFs who fail to give adequate notice to the overpayment to be refunded, a payment which could be calculated for different termination dates at the time the contract is signed.

Staff also urges that a probationary period like that prescribed by PG&E should be applied by all the utilities not only to failures to deliver contracted capacity, but also to failures to maintain QF status or pertinent governmental authorizations, permits, and licenses. With respect to the latter failures, the 15-month period would provide

time within which to correct those deficiencies without risking total contract termination.

The staff also argues that a QF should not be required to provide evidence of its ability to make potential termination payments. Finally, the staff recommends that the utilities should include clear examples in their standard offers of the operation of their termination provisions.

(5) Other Parties

CMA urges that the staff's recommendation of a "50% penalty" for early termination should be rejected as arbitrary. According to CMA, the QF and the utility should submit the matter to arbitration at the time of termination with the burden on the utility to show its actual damages. Other parties seem to suggest that any of the proposed termination "penalties" are arbitrary and should be rejected.

(6) Discussion

Our review of the utilities' termination provisions is not one to determine the utilities' compliance with OIR 2, since our decisions gave no specific directions in this regard, but rather the reasonableness of the utilities' proposals. In making this evaluation, we must initially decide what termination provisions should accomplish and whether those provisions should be standardized between the utilities.

On the first question, we agree with the staff that termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole. With respect to contract standardization, we conclude that there is no reason for the termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions. The type of damages caused to a utility by a QF's termination should essentially be the same for every utility with the actual amount of those damages differing depending on each util-

ity's capacity prices. Without such consistency between termination provisions, a QF could be too greatly advantaged or disadvantaged, for no apparent reason, solely on the basis of its location.

Each of the utilities has chosen to include liquidated damage clauses in its offer. Such clauses are not "penalties" as argued by some Qfs, but are in fact an accepted method of making the party who is not terminating whole. The benefits of a liquidated damage clause include the limitation of damages to the amounts or formula prescribed in the clause and the parties' advance knowledge of how the damages for termination will be calculated. These characteristics of liquidated damage clauses make them desirable and reasonable for inclusion in a utility's standard offer for firm capacity.

We must next consider, however, what elements of a utility's damages should properly be covered by such a clause. All of the utilities have prescribed some method for reimbursement of unearned capacity payments. We believe that such reimbursement is appropriate for the reasons recited by PG&E. In particular, the utility is not required to pay more than its avoided costs for the purchase of energy from a QF. Any payment over this amount arising from price levelization should therefore be refunded to the utility.

The methods chosen by the utilities to calculate this reimbursement appear to result in essentially the same measure of repayment and are reasonable. The only element of the repayment which requires further consideration is the interest to be charged, if any, on the amount refunded. We conclude that to reflect the time value of money, an interest charge is required and further that such a charge should be determined uniformly by the utilities by reference to one source.

While various suggestions have been made, i.e., simple or prime interest rates, we believe that an appropriate

standard is that used in relation to the utilities' balancing accounts. Specifically, we have adopted the commercial paper rate as the charge on funds held in the Energy Cost Adjustment Clause (ECAC) balancing account. In doing so we have made these observations: (1) a variable monthly interest rate, as opposed to a fixed rate, reflects actual market conditions; (2) compounding of interest best reflects the actual burden on the utility and ratepayer; (3) commercial paper is the lowest cost form of short-term borrowing available to the utilities for financing undercollections; (4) the Federal Reserve Statistical Release, G. 13, is a reliable indicator of the interest rate applicable to commercial paper, prime three months; and (5) recognition should be given of the higher cost of financing for SDG&E. (D.91296, 3 Cal PUC 2d 197 (1980).) In D.91296, based on these findings, PG&E, Edison, and SDG&E were ordered to conform the interest rates applicable to their various accounts to "the published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 basis points for San Diego Gas & Electric Company)". (3 Cal PUC 2d at 202.) We conclude for reasons similar to those recited above that this defined commercial paper rate is a reasonable rate to be applied to the repayments required of a QF which terminates its contract.

While we have found reasonable the utilities' provisions for reimbursement in the event of termination, we must also consider whether it is reasonable and necessary for liquidated damages associated with a utility's replacement costs to be specified in the standard offer as well. Further, we must answer whether the amount of the utility's damages should be reduced or eliminated by a QF giving advance notice of its termination. We conclude that the standard offers should include both such provisions.

As stated by SDG&E, with notice depending on the amount of capacity being reduced or terminated, a utility would have sufficient time to replace that capacity, either through purchase or construction, prior to the capacity

actually being lost. Although Edison argues that the utility will incur replacement costs at any time there is a termination, this position fails to recognize the utility's ability to mitigate these costs by being notified in advance of the termination.

We therefore adopt the distinction between QFs which terminate with prescribed notice and those which do not. The evidence in this case regarding appropriate notice periods depending on the amount of capacity being terminated is limited to the specific proposals made by PG&E and SDG&E. We believe that such a provision, however, can vary between utilities based on their best estimates of the time it will take them, given their individual operations and planning, to replace the lost capacity. We have no reason to question either SDG&E's or PG&E's notice periods. Edison, however, will be directed to prescribe a table similar to that used by those utilities prescribing varying lengths of notice for the amount of capacity being terminated up to the maximum capacity any QF could have. Thus, upon termination, QFs giving the prescribed notice will only be required to reimburse the utility for overpayments.

For QFs who fail to give the requisite notice, we find reasonable for all utilities PG&E's approach to calculating the damages to be added to the refund for overpayments. PG&E's formula is less complex than that used by SDG&E, provides certainty with respect to the QF's financial obligations upon termination, and recognizes the value of the notice which is actually given.

PG&E's proposal, however, requires one modification. Under the terms of PG&E's offer, a QF is required to pay only one year's worth of the utility's replacement costs. If the notice periods adopted by PG&E and the other utilities are a true reflection of the time which the utility needs to replace the lost capacity, the adopted damage formula should reflect that needed time. Thus, a QF which

was required under the contract to give five years' notice of termination, but only gave two, should be obligated to pay three years' worth of the utility's replacement costs. For those QFs with notice periods under one year, as provided in PG&E's standard offer, the damage formula should also be adjusted to reflect a payment of replacement costs which corresponds to the required notice period.

These modifications are necessary in part to respond to the reasonable requirement that the liquidated damage clause, as much as possible, reflects the utility's actual damages. For this same reason, we reject staff's suggestion that the utilities' references to future capacity prices be deleted from their offers and that the additional payment for failure to give adequate notice be based on 50% of the levelization overpayment. While it would certainly be beneficial for a QF to calculate its exact termination payment at the time of signing the contract, such a circumstance is not one of the principles of termination guiding our decision and, in fact, may conflict with the accepted standard of damages of making the nonbreaching party whole. The replacement costs which the utility will incur will, in fact, depend on the cost of new capacity at the time of termination, not at the time of contract signing.

We also find Edison's requirement that a QF provide evidence of its ability to make potential termination payments burdensome and unreasonable. While Edison is no doubt properly motivated to protect its ratepayers, such a provision is not a usual prerequisite in contracts and does not further the bases for termination provisions. The operating and performance standards of each of the utility's firm capacity standard offers, as modified here, are sufficient to ensure that the QFs signing these offers will be capable and dependable. It is this very group of energy producers which should be encouraged to sign offers and should not be discouraged by unreasonable contract requirements.

Staff's suggestions regarding the application of PG&E's probationary period to capacity reductions has been covered in the previous section. Whether this period also should be applied to failures to maintain certain governmental authorization is not clear. We unfortunately have no evidence to suggest how long it would take to cure such defects. Because other parties had different views and suggestions regarding provisions requiring the maintenance of governmental authorization, we will consider this entire issue in the next decision on these applications.

Because of the various formulas and notice periods to be used in the utilities' termination provisions, the staff's recommendation that the utilities give clear examples in their offers of the operation of their provisions has merit. Each utility's standard offer for firm capacity should, therefore, include such examples.

Finally, we note that a reduction, as opposed to a total termination, of capacity under a firm capacity contract is more similar to a modification of the contract than to a complete breach. Such a capacity reduction should not result in a complete termination of the agreement. The principles adopted above, however, are properly applied to such a reduction. The utilities' termination provisions should, therefore, clearly reflect their application to the amount of capacity being reduced, in the manner adopted by PG&E and SDG&E.

b. Simultaneous Purchase and Sale

In D.82-01-103 we specifically addressed a QF's ability to convert from a simultaneous purchase and sale of energy to a sale of surplus only. The concept of simultaneous purchase and sale is a regulatory convention which allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. A QF would elect this option for economic reasons (i.e., the retail rate being less than the avoided cost).

While we approved such conversions, we also imposed certain restrictions to ensure that the utility and its ratepayers are compensated for any lost capacity costs. In particular, we agreed with PG&E that such a conversion would be conditioned on reasonable notice and full compensation. The conversions were limited to once per year and were subject to the following:

> ". . .The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions." (D.82-01-103, at page 86.)

Many of the QFs participating in this proceeding took issue with both the limitation on the frequency of a conversion and the application of termination provisions to that change. Given our directive in D.82-01-103, however, these issues would more properly have been raised in a petition for rehearing of that order. We further believe that the decision, which is now final, properly addressed these issues. We find no basis for changing our previous conclusions.

We note also that the termination provisions which we have adopted in this order apply to both reductions in capacity as well as a complete termination of the agreement. PG&E's contract language governing the conversion from simultaneous purchase and sale to a surplus-only sale properly directs that a QF which undertakes such a conversion will be subject to termination provisions only for the amount by which the contract capacity is reduced. Specifically, the language of PG&E's contract, Section A-3.2 of Appendix A, reads: "If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D [PG&E's termination provisions] shall apply." We believe that this approach complies with OIR 2 and should be used by all three utilities.

c. Notice of Termination in As-Available Contracts

Edison's standard offer for as-available capacity states in Section 5:

> "This agreement shall become effective on the date of execution by the parties and shall remain in effect until terminated by Seller upon one year prior written notification given to Edison, which notification shall not be given prior to the date the generating facility is operating and delivering energy to the point of interconnection."

Edison justifies the inclusion of this notice requirement as necessary for determining the number of as-available producers which, in the aggregate, will be ready and willing to sell energy and capacity in any particular year.

We reject Edison's argument. The inclusion of such a provision in an as-available contract is unreasonable and in conflict with D.82-01-103. In that order we specifically stated that termination provisions were not appropriate for offers to purchase as-available power. The staff in its brief correctly summarizes the reasoning behind this conclusion:

> ". . .Unlike firm capacity QFs, a QF with an as-available contract is under no obligation to supply power to the utility, and it is paid only for the power it delivers. The QF's incentive to produce power is its economic self-interest, not contractual penalties. Since a QF who terminates its contract is indistinguishable from a QF who chooses not to produce while maintaining its contract, staff sees little purpose in Edison's notice requirement." (Staff concurrent brief, at page 62.)

We will, therefore, direct Edison to delete the notice of termination requirement from its standard offer for as-available capacity.

B. Capacity Prices

D.82-01-103 provides that QFs which sell electricity to the utility shall be eligible for payments based on the costs that the utility system avoids through purchases of such QF power. For the standard offers which are the subject of these compliance hearings, the costs that utilities avoid by purchasing increments of QF power are defined on the basis of a short run incremental or marginal cost methodology. Short run marginal costs on the utility system consist of two components: shortage costs and operating costs. QF receive energy payments for reducing utility marginal operating costs. QFs receive capacity payments for reducing marginal shortage costs on the utility system. This section evaluates the capacity prices which PG&E, Edison, SDG&E propose to pay QFs pursuant to D.82-01-103.

In D.82-01-103 we determined that QFs should receive capacity payments for both as-available and firm sales to the utility. This conclusion reflects the fact that QF output on either basis will increase the amount of electricity available to the utility, increase reserve margins, and make the possibility of outages less likely. Stated another way, QF power will lead to avoided shortage costs and QFs should be paid accordingly.[5]

Shortage costs on the utility system at any given time can be defined as the expected cost of an outage at that time or, more precisely, the probability of an outage multiplied by the customer costs associated with an outage. As the probability of an outage increases during peak demand periods (when reserve margins are diminished) and decreases during off-peak periods, shortage costs will be higher during daily and seasonal peak periods and lower during off-peak periods. Shortages costs can also vary on

[5] As noted earlier, firm and as-available QFs do receive somewhat different payments which reflect the added value of the firm sources.

an annual basis, as reserve margins change from one year to the next.

Because customer outage costs are very difficult to measure on a direct basis, we adopted a proxy for shortage costs in D.82-01-103 and D.82-04-071. Specifically, we used the capital costs of a utility combustion turbine peaking plant, a low-capital cost plant built to meet reliability needs alone, as a proxy for annual shortage costs. This annual shortage cost amount has been allocated disproportionately to peak and semi-peak hours within the year to reflect shortage cost variations.

There is a very clear reason for adopting the capital costs of a combustion turbine as a proxy for annual shortage costs. If utilities manage their reserve margins correctly, they will pursue capacity-related investments up to the point here the last unit of investment costs the same on an annual basis as annual expected customer outage costs or shortage costs avoided through such investment. The combustion turbine represents the marginal capacity-related investment. If marginal shortage costs exceed marginal capacity-related investment costs, ratepayers will benefit by more investment which lowers the higher shortage costs by reducing the likelihood of outages. If marginal shortage costs are less than the costs of marginal capacity-related investments, then investments should be reduced, reserve margins allowed to shrink, and shortage costs to increase. Overall, the utilities will seek to equate avoided shortage costs with the annual cost of the marginal capacity-related investment (represented by the combustion turbine). The combustion turbine is therefore a reasonable proxy for the equilibrium shortage cost value that will exist on the utility system on average.

In the petitions for rehearing of D.82-01-103 the utilities argued that annual shortage costs will sometimes differ from the equilibrium or average combustion turbine capital cost level. Therefore, they argued, QF capacity prices

should vary accordingly. In D.82-04-071 (pp. 2-3), we concluded that while the use of the combustion turbine proxy "is consistent with an incremental fuel cost that will for some time be based on oil and gas", a more precise refinement of the proxy which "varies capacity payments based on the probability of loss of load, perhaps using reserve margins, would be desirable".

D.82-04-071 clearly specified, however, that as-available capacity payments were to be based on the combustion turbine and that any refinements of the proxy were to be considered only in future general rate cases. The language of D.82-04-071 was less clear as to when refinements of the proxy would be considered in the case of firm capacity payments. As noted earlier, pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies for adjusting the combustion turbine proxy and the QF firm capacity payments that are derived from that proxy. Basically, the utilities' methodologies are aimed at reflecting year-to-year variations in reserve margin levels which lead to year-to-year variations in shortage costs.

The two issues before us now are (1) whether or not PG&E, Edison, and SDG&E used accurate combustion turbine costs in calculating their as-available and firm QF capacity prices and (2) whether in the case of firm capacity prices, the utilities' proposed adjustments of the combustion turbine proxy should be adopted.

1. The Cost of the Combustion Turbine

Firm and as-available capacity prices in all of the utilities' filings are based directly or indirectly on the capital costs of a combustion turbine. The accuracy of these plant cost estimates is thus an important issue in this proceeding. The threshold question here is whether or not the combustion turbine costs should be uniform between utilities, based on a "generic" combustion turbine plant, or whether the costs should be more utility-specific.

We agree with the utilities that combustion turbine costs can vary between utilities due to different financing costs, environmental requirements, and locational factors. The costs of meeting a shortage through construction of peaking capacity will legitimately vary from one utility to the next because of these factors. However, it is much less clear why other factors that are not utility-specific in nature, such as forecasts of general economic indices, should vary in the combustion turbine costs estimates adopted for PG&E, SDG&E and Edison. We do not agree with the utilities that these broader indices need to vary by utility to reflect differing corporate assumptions. If corporate assumptions about such items as inflation and oil prices had to be followed, staff and other parties could not challenge such assumptions as they normally do in other proceedings such as the utilities' general rate cases. We will allow for utility-specific cost variation where it is shown to be warranted, but will strive for uniformity in the case of assumptions that are not clearly utility-specific in nature.

The estimation of combustion turbine capital costs and the application of such costs to capacity prices in contracts of different lengths requires estimates of numerous factors. These include combustion turbine construction costs, fixed charge rates, plant economic life and book life, fixed operations and maintenance costs (O&M), fixed administrative and general costs (A&G), fuel inventory costs, escalation rates, and discount rates. We will consider these factors in the context of each of the utilities' capacity price filings.

a. Edison

Staff and IEP argue that Edison's basic combustion turbine capital cost, $415/kW, is too low, and argue instead for $450/kW based on Edison's CFM-IV filing and staff's "generic" combustion turbine estimate. Edison argues that the $415/kW number is an estimate based on a January 1, 1982 on-line date and that its CFM-IV estimate was a

"rounded" version of a combustion turbine with a June 1, 1982 on-line date. The latter is a higher figure because of inflation. We find that Edison's estimate is reasonably close to staff's "generic" turbine estimate and that it is consistent with the combustion turbine proxy that we adopted for rat design purposes in Edison's test year 1983 general rate case. Also, the January 1 number is more consistent with the average year rate base fixed charge rate methodology that is used by Edison and staff. Therefore, we will adopt $415/kW for 1982 combustion turbine capital costs for Edison.

To spread the combustion turbine capital costs to capacity prices over the years of various QF contracts, including the single year as-available contract, fixed charge rates and constant dollar factors are used. These factors depend in part on the economic life that is assumed for the combustion turbine. Edison argues that a 30-year economic life should be used. This period, in Edison's view, is a realistic estimate of the useful life of such a plant. Staff and IEP counter that Edison uses a 23-year assumption to depreciate its own plant and that a 30-year assumption is inconsistent with this approach and artificially disadvantages QFs.

We have previously considered this issue in D.93887 (p. 175), in which we decided that PG&E should use a 24-year combustion turbine useful life assumption consistent with its own depreciation schedules. Edison's assumption is inconsistent with D.93887 and with PG&E and SDG&E filings in this proceeding. We will adopt the 23-year economic life for Edison's capacity prices. Any change by Edison in its own depreciation schedules to more closely reflect its estimate of useful plant life made in this proceeding should be considered in Edison's general rate case.

Escalation and discount rates also affect the combustion turbine-based capacity price stream for different contract lengths and different start-up dates. The 15% discount rate

used by staff and Edison, based on an estimate of Edison's incremental cost of capital, is reasonable. The escalation rates for capacity prices, fixed O&M, and fuel prices used by staff are reasonable. Edison argues that these latter staff assumptions are at odds with its corporate assumptions used for planning purposes in general. We believe that these are factors which are not utility-specific in nature. The use of the staff assumptions here is consistent with adoption of the same assumptions for PG&E's and SDG&E's combustion turbine cost estimates discussed below.

The staff fuel price assumption is only important for combustion turbine cost estimation if the combustion turbine fuel inventory cost escalates over the life of the unit. Edison contends that this fuel inventory cost should not be escalated. In effect, Edison assumes that gas will always be available for use in the turbine over the life of the unit and that the liquid fuel inventory will never be used. Staff and IEP argue that the inventory costs should be escalated, using their oil price escalation assumptions. Staff argues that gas may not always be available and that even if it is, it may not be the cheaper fuel option. Therefore, the inventory will be used and replaced over time. The staff escalation rate assumption implicitly assumes that the inventory will be replaced annually.

We conclude that the most reasonable assumption lies between the staff and Edison positions. It is unlikely that the inventory will be replaced annually and such an assumption may overstate avoided fuel inventory costs, particularly since Edison normally uses first-in-first-out (FIFO) fuel inventory accounting. The assumption that the inventory will never be turned over, however, is equally unrealistic. We will adopt an escalated fuel inventory using 50% of the staff's annual escalation rates, reflecting partial annual use of the inventory over time.

Another item of contention between Edison, staff, and IEP, is the proper amount of fixed A&G costs that should be capitalized as a part of the combustion turbine costs. Edison uses 1% of the capital costs of the plant as a measure of levelized annual A&G costs over the life of the plant. Staff uses 1% of the capital costs of the plant as a measure of the first year A&G costs and escalates this figure over the life of the plant. The result is equivalent to a 1.6% levelized A&G figure. Staff argues that Edison used the 1% escalating figure in its most recent general rate case. IEP argues that at 2% levelized figure should be used, citing a 1982 staff study that showed Edison's A&G costs to be a 2% or higher percentage of fixed plant. Edison in this proceeding repudiated its rate case marginal cost A&G assumption and questioned the applicability of the staff calculations in Exhibit 16 upon which IEP relied in making its argument.

It is apparent from the record here that the relationship between A&G costs and fixed plant additions is not fully understood. We agree with Edison, however, that the degree to which A&G costs are actually avoided by QF purchases is problematic. Under these circumstances, a conservative approach is appropriate in prescribing the A&G measure. We will therefore adopt Edison's 1% levelized figure for A&G.

Staff, IEP, and Edison also disagree on the appropriateness of Edison's "differential fuel credit". Edison includes in its combustion turbine capital costs a measure of the increased fuel costs that occur, above the system marginal operating cost, when the combustion turbine is actually operated. We agree with IEP and staff that Edison should account for this increased marginal operating cost not in the combustion turbine capital cost, but in its estimate of the system marginal operating cost. In other words, the costs of operating the combustion turbine should be reflected in QF energy prices, not capacity prices.

Finally, we note that Edison in its brief argues that the staff's fixed charge rate in Exhibit 71 differs from Edison's rate for reasons other than the varying fixed charge rate assumptions of the two parties. This circumstance appears to be purely a computational problem. We will direct Edison in this order to file capacity prices that are based on combustion turbine costs that reflect our preceding conclusions about costs.

b. SDG&E

SDG&E's capacity price filing utilizes a combustion turbine capital cost of $400/kW. Staff argues, as it did in the case of Edison, that $450/kW is a more appropriate figure. Staff found the SDG&E estimate to be too low because of inadequate allowance for cost overruns, pollution control requirements, new site costs and other factors. SDG&E counters that its allowance for cost overruns is consistent with historical experience, that it has included requisite pollution control costs, and that it is unrealistic to include new site costs given that SDG&E would be much more likely to add combustion turbines at existing sites.

IEP argues that the combustion turbine cost used in SDG&E's test year 1982 rate case (A. 59788), $618/kw, should be used for capacity prices here. SDG&E states in Exhibit 37 that the rate case figure reflects a 500MW combustion turbine development at a new site with an anticipated baseload mode of operation. The OIR-2 filing reflects the avoided costs of a 50MW peaking unit at an existing site.

We will adopt SDG&E's capital cost estimate of $400/kw. It is reasonably close to Staff's "generic combustion turbine" estimate and the reasons for its being lower, such as the use of existing plant sites, are justifiable on utility-specific grounds. We agree with SDG&E that their rate case cost estimate is based on a plant type that does not sufficiently reflect the marginal peaking capacity investment that we have chosen for the shortage cost proxy.

Staff and SDG&E differ on the proper escalation rates to be used for capacity costs, fixed O&M, and fuel prices. Consistent with our discussion of the Edison combustion turbine costs, we will adopt the staff estimates. We do, however, agree with SDG&E that more recent, lower inflation rates should also lead to a lower estimate of the incremental cost of capital that is used in the fixed charge rate. We will revise the staff figure of 16.5% down to 15.5%. This approach is consistent with the estimate used for Edison while also taking into account the different credit ratings of the two utilities.

The record is silent on whether SDG&E included an A&G cost in its combustion turbine cost estimate. We agree with staff, which argues in its brief that an A&G component should be included. SDG&E A&G costs should be commensurate with those adopted for Edison.

Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and the economic life of the plant. We will adopt these figures. For the purposes of calculating capacity prices, SDG&E will be directed to utilize combustion turbine costs which conform to the foregoing conclusions.

c. PG&E

PG&E filed capacity prices that were based on combustion turbine capital costs of $770/kw. This estimate was taken from PG&E's most recent general rate case. (D. 93887). Staff argues that, unless the Commission uses a generic combustion turbine cost, it would be simpler to use the rate case number used by PG&E. IEP concurs that the rate case estimate should be used, but offers several suggestions about various combustion turbine costing assumptions should the issue be considered anew.

We do consider it to be important to examine the combustion turbine cost assumptions in this decision rather than merely accepting estimates from previous rate cases.

We indicated in D.82-01-103 and D.82-04-071 that the combustion turbine was a reasonable proxy for shortage costs. The purpose of these compliance hearings was to examine the adequacy of the method by which the utilities translated this concept into capacity prices.

From the perspective of the record in this proceeding, in which three utility filings were considered together, PG&E's capital cost estimate from its rate case appears to vary from that of the other utilities by an unreasonable amount. This variance is wider than one could reasonably expect from utility-specific factors alone. Therefore, we will not adopt this estimate and will instead adopt the staff's generic combustion turbine capital cost of $450/kw for PG&E. This estimate is closer to our adopted capital costs for Edison and SDG&E.

We agree with IEP that if one combustion turbine cost estimate from PG&E's rate case is examined and updated here, other assumptions should be examined a well. We will therefore not adopt staff's use of the rate case escalation and discount rates. Instead, we will adopt for PG&E the more recent estimates for capacity price, O&M, and fuel price escalation that staff has recommended for Edison and SDG&E. We will adopt a 15.0% incremental cost of capital which is consistent with our adopted discount rate assumptions for Edison and SDG&E.

IEP notes that the rate case combustion turbine estimate did not include a fuel inventory cost. To ensure consistency, we will direct PG&E to include a fuel inventory cost component equivalent to that adopted for Edison.

We find that the assumptions used by PG&E in its rate case estimate as to the economic life of the turbine, fixed O&M costs, and fixed A&G costs are reasonable. We will direct PG&E to derive capacity prices based on combustion turbine cost assumptions adopted in the foregoing discussion.

2. Adjustments in the Combustion Turbine Proxy for Firm Capacity Payments

As noted earlier, in these compliance hearings the utilities proposed that their firm capacity prices be based on methodologies that adjust the combustion turbine shortage cost proxy for year-to-year variations in reserve margins and reliability. Staff supported these methologies in concept, but criticized several specific elements of the methods. Also, staff argued that because of the uncertainty over the accuracy of the methods and the related assumptions, a "floor" on downward adjustments of the combustion turbine proxy should be adopted. The floor capacity price in any contract year would be 50% of the annual combustion turbine cost.

IEP, Occidental, the State Energy Task Force and other QFs opposed the utilities' methodologies, arguing that they were given inadequate opportunity to examine these methods in the hearings. Further, the limited examination that did take place showed that the utilities' methodologies were seriously flawed.

We will consider all of the parties' positions in the context of each utilities' proposed shortage cost methodology.

a. PG&E

PG&E proposes that the combustion turbine proxy be set as the maximum annual shortage cost and that this value should be adjusted downward in years in which reserve margins are forecasted to be above target levels. PG&E proposes that this downward adjustment be based on an Energy Reliability Index (ERI). The ERI is derived from PG&E's Generation Reliability and System Simulation Model (GRASS). The ERI is a probablistic measure of the expected size and frequency of reduced electric energy deliveries which are forecasted to result from generation capacity limitations in future years. An ERI number is derived for each future year in which firm QF capacity prices must be calculated. In years in which

PG&E's reserve margins are expected to be smaller than or equal to target levels (with loss of load probabilities greater than or equal to the target one day in ten years), the ERI adjustment factor is set at 1.0 and the QF capacity price is set at the full combustion turbine cost level. In years in which reserve margins are atypically large the ERI adjustment factor is calculated as the ratio of the ERI in the large reserve margin year in question to the ERI in a base year when reserve margins are at their target levels. This ratio, a number less than one, is multiplied by the full combustion turbine cost to produce a QF capacity price for that year which is less than the full combustion turbine proxy.

We believe that PG&E has presented an innovative methodology for measuring shortage costs. However, we agree with other parties in the proceeding that the method is underdeveloped and suffers from several important flaws in both concept and actual application.

One important conceptual flaw is that the ERI method is biased because it allows for *downward* adjustments in the shortage cost proxy when reserve margins are above target levels, but does not allow for *upward* adjustments in years in which reserve margins are below target levels. We agree with Occidental and IEP that such upward adjustments should be a part of any precise shortage cost methodology. Clearly, as noted earlier, the combustion turbine is a proxy for the equilibrium or average shortage cost value. Actual shortage costs will vary above and below the equilibrium value, due to the "lumpiness" of powerplant capacity additions. This circumstance is especially true in the case of shortage costs for the near term, a time frame in which unexpected demand increases cannot be met with new plant additions because of the lead time associated with new plant construction. In calculations of longer term shortage costs, an upper limit equal to the cost of a combustion turbine proxy may be appropriate, depending on the precision on forecasts.

A second conceptual problem with the PG&E method is that it treats many of the uncertain factors that affect future reserve margins in a deterministic fashion. It is a basic tenet of supply planning that the greater the uncertainty about future demand levels, plant start-up dates, and plant maintenance requirements, the greater the reserve margin "insurance premium" that is needed. For PG&E's assumptions not to reflect the uncertainty about these factors is to understate reserve needs. As PG&E has stated in its CFM-IV filing:

> "The explicit inclusion of uncertainty will always require a larger reserve capacity to maintain the same level of reliability, given the assumed certain outcome falls in the middle of the range of possible outcomes . . . PG&E's (supply) planning reflects this consideration." (Ex. 68).

We agree with Occidental that, if uncertainty leads PG&E to increase its estimates of shortage possibilities and reserve needs for its own supply planning purposes, PG&E, to be consistent, should also take this uncertainty into consideration in calculating capacity payments to QFs. If this approach is not used, QF capacity value will be understated.

Another shortcoming related to the development of the PG&E methodology is PG&E's failure to perform a sensivity analysis on the ERI model to investigate whether or not the ERI results would be drastically altered by small changes in input assumptions. PG&E has argued that the ERI results are not likely to be sensitive. Staff points out in its brief, however, that the evidence indicates otherwise. The relatively small adjustment PG&E made during the proceeding in its input assumption about load management achievements led to a relatively large change in the ERI result. In general, the lack of sensitivity analysis casts doubt on the validity of the ERI results.

Apart from these weaknesses in the PG&E shortage cost methodology itself, numerous questions arose during the hearings about the application of the methodology to the standard offers. It appears that PG&E used several erroneous input assumptions when it calculated ERI adjustment factors and derived its proposed QF capacity prices. Start-up dates for the Diablo Canyon nuclear plant and the Helms pumped storage facility were assumed to be January 1, 1982, and August 1, 1983 respectively, both of which are incorrect. Future forced outage rates on plants such as Rancho Seco and Contra Cost 1 were assumed to be much less than the outage rates experienced historically. The derating of the Pittsburgh 7 plant was not taken into account. Demand forecasts were based on older, higher oil price assumptions and therefore were probably understated. Demand may have also been understated, in turn understating shortage costs, because the forecast load management goals were assumed to have been fully achieved.[6]

Forecasts of future reserve margin levels are obviously extremely difficult undertakings which involve many assumptions about future loads and resources. PG&E's assumptions were not adequately substantiated in the hearings. Many of the assumptions appear to have the effect of understating future shortage costs and QF capacity payments.

PG&E offered two revisions of its assumptions which lessen this problem to a certain degree. First, the extent of its assumed load management achievement was reduced.

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[6] We note in passing that while load management *goals* should not be included, we do not agree with Staff and IEF that load management should not be included *at all*. Rather, we concur with Edison's argument in its brief that load management, utility resources, and QF power must be considered, to the extent feasible, simultaneously, not sequentially, in the estimation of future shortage costs. However, load management assumptions must be conservative, especially when estimating the impact of voluntary programs.

Second, PG&E offered to make a retroactive upward revision in QF capacity payments if the Helms and Diablo start-up dates were not realized.

We consider the retroactive payment revision undesirable because it does not signal QFs prospectively about the value of their future performance. More importantly, we do not consider these two proposed revisions of PG&E's capacity input assumptions are sufficient to alter our conclusion that the ERI input assumptions result in understating shortage values and QF capacity payments.

Because of the methodological flaws and questions surrounding PG&E's input assumptions we will not adopt PG&E's shortage cost methodology. While we will not preclude new proposals in future hearings aimed at refining the shortage cost proxy, at this time we conclude that PG&E's firm capacity payments, like its as-available payments, should be based on the basic combustion turbine proxy, using the combustion turbine cost assumptions adopted previously in this decision.

b. SDG&E

SDG&E proposed a shortage cost methodology which is similar to PG&E's. In SDG&E's methodology, an annual "probability of need" is calculated using SDG&E's production simulation model, PROMOD. The probability of needing capacity varies from year to year as reserve margins vary. The maximum value of the probability of need is 1.0, and in such years QF capacity prices are set equal to the full combustion turbine. In years when reserve margins are above target levels, the probability of need is less than one and the full combustion turbine capacity price is adjusted downward accordingly.

In its brief SDG&E claims that certain criticisms of PG&E's method do not apply to SDG&E's methodology. In particular, SDG&E claims that it uses more realistic input assumptions in its reserve margin forecast. For ex-

ample, forced outage rates on existing units are assumed in the PROMOD forecast to be similar to those experienced historically by the plants. Forced outage rates on new units are assumed to be higher than those experienced by other utilities with plants of the same type, to provide "a cushion against error". Finally, SDG&E asserts that it *has* taken into account the impact of more recent, lower oil price forecasts in its demand forecast and reserve margin forecast.

In evaluating SDG&E's shortage cost method, it is immediately apparent that this method includes certain flaws similar to those enumerated for PG&E. For example, a basic methodological shortcoming is that the shortage cost proxy can only be adjusted downward and can never exceed the equilibrium or average combustion turbine level. Further, an increasing shortage cost trend through the years can, under SDG&E's method, never be followed by any downward trend, even if this situation more accurately reflected reserve margin changes. Finally, with respect to input assumptions, it appears that uncertainty about new plant on-line dates was not taken into consideration and that, for example, an unrealistic assumption was made about SONGS 2 being fully available by the beginning of 1982.

It is difficult to evaluate the extent to which SDG&E's method suffers from flaws in data and methodology because SDG&E's shortage cost method was not sufficiently examined during the hearings. SDG&E changed its methodology late in the proceeding after staff had already undertaken its evaluation of SDG&E's capacity prices. SDG&E did not adequately substantiate its new method and the input assumptions that it used. The ALJ ordered SDG&E on October 15, 1982 to provide data on its input assumptions and its methodology in keeping with our decision in OII-26 which set up certain requirements to substantiate evidence in cases involving computer simulations. Such information was to be provided to staff and the State

Energy Task Force during the briefing schedule. However, both staff and the State Energy Task Force indicate in their briefs that they had still not received the data at the time briefs were completed in mid-November.

Because SDG&E's methodology appears to have certain flaws similar to those found in PG&E's approach and because SDG&E did not adequately substantiate its proposed refinement of our adopted shortage cost proxy, we will not adopt SDG&E's proposal. Instead, we find that the basic combustion turbine cost is an adequate proxy for shortage costs and should be used for SDG&E's firm capacity payments. This finding is consistent with D.82-01-103, with SDG&E's as-available capacity price, and with our previous conclusions relating to PG&E's firm capacity price. As we noted in the case of PG&E's method, our adoption of the basic turbine shortage cost proxy for firm capacity prices does not preclude the further consideration of more precise shortage cost methodologies in future hearings.

c. Edison

Edison's proposed refinement of the combustion turbine proxy represents a different methodology than that proposed by PG&E and SDG&E. Rather than adjusting the combustion turbine proxy to reflect the results of computer simulations of likely future reserve margins, Edison proposed that QF capacity prices should equal the price of wholesale market capacity contracts between 1982 and 1985 and full combustion turbine costs thereafter.[7] The wholesale market price that Edison primarily relies on for

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[7] The combustion turbine costs are based on the value of deferring a combustion turbine over the length of the contract. This is a slightly different approach for deriving the levelized price for different contract periods than that used by PG&E. PG&E applies a real economic carrying charge to an annually inflating turbine cost and levelizes the resulting escalating payment stream. Both approaches should lead to the same result given the same assumptions and either is acceptable.

1982-1985 QF capacity prices is the emergency capacity price in the California Power Pool Agreement. Secondarily, Edison states that this price is also supported by the Edison - California Department of Water Resources Contract and the Principles of Interconnected Operations for the Navajo and Four Corners Power Projects. Edison contends that its $24/kW/yr 1982-1985 capacity price for QFs is quite generous. Edison points out that it would only pay such a price for emergency purchases under its wholesale contracts if it were to take emergency power for the entire 12 months of the year. In Edison's view, such a circumstance is very unlikely.

The State Energy Task Force contends that the wholesale contracts that Edison relies upon for its 1982-1985 QF capacity price are complex energy and capacity exchange agreements that involve shared services. Because it is part of such a package, the State Energy Task Force claims the emergency power price cannot be isolated and used by Edison in developing its shortage costs.

The State Energy Task Force's claim has merit. It is quite possible, for example, that, within these reciprocal exchange agreements, emergency power services are mutually underpriced by the parties to the agreement. If this is so, taking the California Power Pool Agreement as an example, then a QF which allows Edison to avoid a capacity purchase from PG&E would be avoiding Edison's capacity purchase costs and PG&E's costs which are not covered in the purchase price. The fact that the price of emergency power in the California Power Pool has not changed since 1964 despite inflation and narrower reserve margins makes this possibility quite plausible.

Edison argues that it is necessary to focus on the costs that it actually avoids when it does not make a wholesale contract purchase, not any additional value of the service that may not be reflected in the purchase price (or any additional cost that may be avoided by another utility else-

where). However, if we return to the California Power Pool example, it can be seen that such a focus may not yield accurate avoided cost price signals. If PG&E and Edison were to base QF capacity prices on a mutually underpriced reciprocal exchange service, the additional costs that QFs actually avoid, but are not reflected in the price, would never be included in QF capacity prices of either utility. This possibility weakens the validity of Edison's argument.

A second criticism of the Edison method is that the wholesale contract price is not necessarily a reasonable proxy for the utility's marginal shortage cost. The existence of wholesale contract capacity does not indicate whether or not the contract capacity represents the marginal resource. Is the contract the most expensive increment of capacity on the system (more expensive than other capacity contracts or load management programs of other resources)? Is the contract the resource that would be avoided if QF power was accepted? Even within the narrow sphere of wholesale contracts alone, it is not clear that emergency power contracts are the type of contracts that would be displaced by constant purchases of firm QF power. Under emergency power agreements, infrequent use of the service is normally assumed by the seller. Constant firm purchases might lead to a different type of wholesale agreement and price. The latter might be a better measure of avoided cost.

A clear conclusion on the accuracy of using wholesale emergency contracts as the marginal shortage cost proxy would require more evidence about all of Edison's wholesale contracts, company-owned resources, and load management programs. We are hampered in our analysis, as we were in the case of SDG&E, by Edison's inadequate offering of data during the proceeding. For example, the State Energy Task Force submitted to Edison a data request on August 27 asking Edison for information about its capacity price methodology based on wholesale con-

tracts. The information which was sought included (1) the contracts that were used to set the $24/kW/yr 1982-1985 price and (2) other contracts that exist, but were not used to set the QF capacity price. This information is exactly the type required to ascertain the validity of the price calculation and the degree to which the contracts upon which that calculation is based represents the marginal resource in the context of all such contracts.

Edison responded on September 21 that "much of the specific information sought is proprietary in nature". During subsequent hearing dates, however, it because apparent that the contracts in question are public documents filed with the Federal Energy Regulatory Commission.

In view of the doubts cast on the wholesale capacity price resulting from the reciprocal exchange arrangements upon which it was based, and in view of the inadequate showing indicating that the chosen contract price was an accurate reflection of Edison's actual avoided shortage cost, we cannot adopt Edison's proposed methodology. As we have done in the case of PG&E's and SDG&E's firm and as-available capacity price and Edison's as-available capacity price, we will adopt the capital cost of the combustion turbine as a reasonable proxy for shortage costs for Edison's firm capacity prices. This conclusion does not preclude the adoption of a more precise shortage cost methodology for Edison in future hearings and does not preclude the use of wholesale capacity prices in such a methodology.

3. Conclusions on Capacity Prices

In D.82-04-071 we concluded that: "At present the gas turbine is the best surrogate we have for capacity and it is consistent with an energy payment based on oil or gas." (Mimeo, page 3.) We reaffirm that conclusion today. In reaffirming this conclusion we do not posit that the combustion turbine is the most exact measure of avoided shortage costs. Given the evidence in this proceeding we

essentially face a choice between imperfect measures of avoided shortage costs: (1) the utilities shortage cost measure, which have been inadequately substantiated and shown to be biased downwards in certain respects and (2) the combustion turbine proxy which is also an inexact measure and has been argued to be biased upwards. Given this imperfect choice and the uncertainty surrounding avoided shortage costs, we choose the combustion turbine alternative because it gives a stronger incentive to cogenerators and small power producers. This is proper, we believe, because these power sources bring with them many important benefits to ratepayers which are difficult to quantity and not captured in the avoided cost calculation.

We will direct the utilities to file as-available and firm capacity price schedules based on the capital costs of the combustion turbine, using the combustion turbine cost assumptions adopted earlier in this decision. We also conclude that the possibility of developing a more refined shortage cost methodology which accounts for year-to-year variations in reserve margins is worth exploring further. The issue will be raised in PG&E's and SDG&E current rate cases, and in Edison's five-year forecast energy price offer (A.82-04-46). Any revisions to capacity tables will be made prospectively for new contracts. They will not apply to QFs which have already signed firm capacity contracts.

Energy Payments

A. General

D.82-01-103 stated that energy payments should be derived from a utility's shortrun operating costs, reflecting the variable cost of providing an additional unit of electricity. In calculating the energy prices, the intent of the decision was "to capture as accurately and timely as possible the current marginal energy costs incurred by the utility." (D.82-01-103, page 31.) The decision stated that the current practice was to use the previous three-month oil costs and forecasted incremental heat rates. In a later

decision (D.82-11-087), the Commission made a revision and adopted prospective fuel prices in the event that gas was the marginal fuel.

The parties in the case representing small power producers generally were concerned by the unpredictability of the energy prices and by their inability to verify the calculation of these numbers. Various suggestions were made to provide more certainty, including proposals to include formulas for energy in the contract, to use average annual incremental heat rates, to establish price floors, and to levelize the energy payments over time. In general, the utilities have rejected such proposals as being unworkable, overly burdensome, or unresponsive to changing conditions.

We resolve these conflicting concerns by ordering utilities to provide a much certainty as is possible in their contracts and procedures without undermining the basic concept of using the avoided energy price applicable to these standard offers. The risks QFs take relating to energy prices in these offers are not unlike the risks in a competitive spot market. For example, small power producers take the risk of changing utility fuel costs in future years as they influence the marginal energy rate. It is also consistent for incremental heat rates to fluctuate since, in fact, these rates will vary depending on future supply and demand conditions in utility operations.

SDG&E argues that the Commission's program to develop small power production "significantly reduces the QF's obligation to compete in an open and free market for the sale of QF generated power." Noting that "the QF receives a payment for its power from a regulated environment instead of an open market", SDG&E argues that "[t]his substantial reduction of the risk in a QF's operation, compared to an open market business operation, is an unprecedented preferential benefit provided by the State of California to unregulated businesses." (Brief, page

3.) We disagree. As described above, QF prices behave similarly to those in a competitive supply market, and the pricing does create considerable risks for QFs, not unlike those in a competitive market. In fact, our concern is that the administratively established prices in this program may create *more* risks for QFs than would open market prices. Unlike a free market, administrative changes can affect basic pricing methodologies, not just changes in supply and demand conditions. We agree with QFs that these risks should be mitigated whenever possible.

One major administrative risk implied by the proposed contracts is the possibility of a change in pricing policy by future Commissions. Specifically, as the contracts currently are written, some future Commission could order that a new pricing policy be adopted with prices derived at less than avoided costs. We do not believe such discretion is appropriate. While a future Commission may have the prerogative to implement pricing policy changes prospectively for new small power contracts, QFs which have already built projects should received payments derived from the pricing methodology in existence when the project was built. Otherwise, far too much price uncertainty will exist. Accordingly, we will order that utilities include a provision in all their standard offers before us which assures QFs that they will receive payments throughout the life of the specific project derived from the utility's full shortrun avoided energy costs, as approved by this Commission. This requirement will ensure that a framework is established firmly, with prices derived from a utility's full avoided costs. Since these contracts are viewed as reasonable, per se, the utility's expenses for such purchases can be assured (D.82-01-103, page 24). Such a provision does not add to utility risks as suggested by the utilities.

The second major administrative risk for small power producers not present in a competitive market is the model used for calculating the avoided cost payment. Unlike most

markets in which buyers and sellers meet at arm's length to establish prices (i.e., the stock market or a commodity market), the prices established for small power producers are derived from models in possession of the utilities as approved by this Commission. Not surprisingly, the small power producers are skeptical of this arrangement and would at least like these models to be more explicit and understandable. We agree that this concern is significant. We will therefore require that utilities present, in detail, the assumptions behind their energy price calculations and that QFs have an opportunity to critique the assumptions in the utility models.

To provide greater certainty and clarity, some QFs suggest that an energy price formula be written into the QF contract. We do not find such an approach to be feasible. The pricing formula is highly complex and could not suitably be incorporated. Furthermore, while QFs should have the certainty that their prices will reflect the utilities marginal variable costs, the actual model for calculating such costs may become more refined in the future. A specific formula would preclude such refinements. By clearly establishing that prices should reflect the utilities' shortrun avoided costs in the contract and by giving QFs an opportunity to review and comment on the utilities' calculations, we believe sufficient certainty is provided as to how these payments are to be derived.

B. Determination of Energy Prices

While the policy to establish prices from the utilities' shortrun marginal operating costs is generally understood, there remains a considerable debate on how to calculate those rates. The utilities' marginal operating costs vary almost continuously, and at least at this time the metering technology does not exist to signal prices so frequently. As a result, the *average* marginal cost applied for a particular time period must be used. One issue concerns how long this periods should be and under what conditions the

prices may be adjusted from the average marginal rates. A second major issue concerns whether the methods used by utilities for calculating the marginal operating costs for a particular period are accurate.

We generally resolve these issues in two ways. First, to the extent possible, this decision addresses the specific concerns raised by the parties relating to the calculation of energy prices. However, it is clear from this proceeding that not all of the potential issues relating to the calculation of energy prices were addressed. We expect that the parties will want to offer further comments and refinements in the future. Therefore, in addition to resolving many specific issues here, we will provide a procedure by which QFs and other parties can provide comments in the future. We do not provide this procedure as a forum to relitigate issues, but to allow new issues to surface. Small power producer pricing remains in an evolutionary stage, and we have not doubt that issues will continue to arise about how prices should be established within the guidelines established in D.82-01-103.

1. Incremental Heat Rates

One significant issue in this case was how often a utility's incremental heat rates should be revised for determining prices to small power producers. Incremental heat rates, which reflect the efficiency with which utilities can burn fuel at the margin, are one component in the determination of the marginal cost of electricity. IHRs vary depending upon what plants are in operation at any particular time.

Currently, incremental heat rates are determined biennially in the utilities' general rate cases, with heat rates varying by time of day and season. These incremental heat rates are used for determining the prices during the two-year period after a rate case is completed, using fuel costs which are updated quarterly (for PG&E and SCE) or three times a year (for SDG&E). If actual incremental heat rates

deviate from the projected average heat rate developed in a rate case due to hydro conditions or any other reason, this change is not reflected in the quarterly prices.

QFs generally favor using the average annual heat rate approach because it provides more price stability. Administratively, QFs also object that utilities may deviate from the average annual heat rate when it suits their interests (e.g., when hydro conditions are favorable and the incremental heat rates generate relatively low prices). PG&E suggests that average annual heat rates be used now, but suggests that projected actual year heat rates (accounting for hydro conditions) might be desirable in the future to more closely reflect actual shortrun operating costs.

By separate petitions for modification filed September 10, 1982, CMA and Imotek, Inc. asked the Commission to clarify D.82-01-103, and find that utilities should use average annual incremental heat rates for determining avoided costs, as determined in the most recent rate case. The petitioners argue that actual year heat rates create instability in QF prices and are unverifiable. We will respond to this petition in this opinion.

We resolve that, for now, average year incremental heat rates should be used in the determination of avoided costs as determined in the utilities' rate cases. We have no procedure at this time for verifying more current estimates, and we do not think it appropriate to adopt more frequent estimates without giving parties the opportunity to comment on the methodology. However, we conclude that actual year incremental heat rate calculations would be preferable because they more accurately reflect actual marginal operating costs. QFs that are able to respond to the higher price signal in a dry year, for example, would have a greater incentive to provide energy when it is more needed. On the other hand, small hydro producers whose fluctuations in electric supply parallel those of utility hydro plants are likely to be overpaid using average hydro years,

as in the current method, since they would be likely to produce relatively little in low hydro years (when actual avoided costs are relatively high) and relatively more in high hydro years (when actual avoided costs are relatively low).

While we are adopting average annual heat rates now, we will ask utilities by September 30, 1983 to make proposals for a procedure to use projected actual year incremental heat rates. The utilities in their proposals should clearly set forth how they intend to forecast hydro conditions which would then be used to forecast actual year heat rates. The IHR forecasts probably should be made in the spring to take into account hydro conditions. We will not adopt any proposal until parties have had an opportunity to review and comment on it. Utilities should not deviate from the current two-year review procedure until the deviation has been expressly approved by this Commission.

Another issue raised by staff was how to handle new plants that come on line which effect IHRs. D.82-01-103 at page 31 states that IHRs determined in rate cases should not include new power plants because both the operating dates and operational characteristics of new plants are generally unknown. However, should a new facility begin operation between cases, staff recommends that the IHRs be revised in an ECAC proceeding. We will adopt this suggestion.

Both SDG&E and Edison argue that they should not file incremental heat rate data since such data are not explicit outputs of their models. The utilities use probablistic models, which predict the likelihood of a particular plant being on line in any particular hour, and estimate the expected average electricity price based on that model. At some cost the models could be adapted to produce incremental heat rates as outputs. We agree with small power producers that such information would be valuable

and should be provided. Current and expected heat rate data would provide QFs with the ability to determine more realistically prices in future periods. Such costs currently are included as utility administrative expenses. Such accounting would appropriate in this case.

2. Marginal Fuel Costs

Many of the parties were concerned with the fuel costs used in determining the avoided energy costs. Concerns were raised whether forecasted fuel prices, prior period fuel prices, or retrospective prices should be used and how the determination of the marginal fuel at any particular time would be made.

Currently, the energy prices are set by utilities at the beginning of a quarter, and QFs can anticipate that payments will be based on those prices throughout the quarter, except for SDG&E which establishes rates three times a year in ECAC. Adjustments are not made at the end of the quarter to reflect actual conditions during that quarter. This procedure gives QFs a clear and predictable price upon which they can base operations for future periods, but it also results in a relatively less accurate determination of the shortrun operating costs than if prices were established retrospectively with fuller knowledge of what actually occurred. Some suggestions were made in the proceeding that the prices be adjusted at the end of the quarter to reflect actual prices paid during the quarter for fuel. Payments to QFs would be retroactively adjusted at the end of the quarter to coincide with actual fuel prices paid during that quarter.

We conclude that the current procedure of prospectively establishing prices is preferable. This procedure gives QFs a clear price signal from which to determine its operations for the upcoming quarter. In reaching these prospective determinations, we will attempt, as accurately as possible, to project the fuel mix which will occur in the future quarter. Any variations in the projected price should likely

be as high as they would be low, and deviations should cancel out over time. Retrospective adjustment would undoubtedly create significant controversy, be cumbersome and destabilize the market for small power producers.

In D.82-11-087, the Commission ordered the utilities to use current natural gas prices for the determination of prospective avoided operating costs, but to continue to use oil into inventory when oil is the marginal fuel. We will continue to adopt this approach for now, though we would consider refining the oil and natural gas price numbers to include projections instead of current prices in the future. For now, we conclude that projecting oil and natural gas prices would be unduly complicated.

A major controversy in this case was the determination of whether oil or gas is the marginal fuel at any particular time. In recent months, oil in inventory has been more expensive than natural gas. QFs have been concerned that utilities have been burning oil while claiming that natural gas is nearly always the marginal fuel. In response, utilities argue that they must burn oil in inventory either to avoid underlift payments or for various other reasons which preclude oil from actually being the marginal fuel. IEP questions the utilities' assertions and suggest, as a simplifying assumption for calculation, that oil should be presumed to be the incremental fuel on any day it represents 10% of the generation mix. Staff in evaluating this issue concludes that oil is not generally an avoided fuel at this time, and that the 10% oil mix assumption is arbitrary.

It appears that the question of whether oil or gas is the marginal fuel will involve specific issues that vary in each quarter. Accordingly, our approach will be to ask each utility to file its projected marginal fuel mix in each quarter and allow parties an opportunity to critique these projections. Each quarter the utilities should also submit information on their actual experience in the prior quarter. Any

decisions reached by the Commission to modify these prices should provide guidance for future quarters.

Much time was spent in this proceeding on the issue of whether Edison avoided oil in the first quarter of 1982 or whether it primarily avoided gas. As some of the parties point out, the resolution of this issue has implications for future quarters as well. Edison argues that while oil was burned during this past year, it was not marginal because it was burned either for testing or to avoid underlift charges in Edison's long-term contracts.

Edison's response appears to be accurate. We conclude that the basic conceptual problem is that the oil prices used in the determination of avoids costs are based on long-term contract prices and therefore may not reflect current fuel markets. When a utility avoids burning oil, it may not be able to avoid the full long-term contract price paid for it when it must either sell the oil on the spot market at a price less than the contract price or refuse to take additional oil from its supplier to control inventory and pay underlift charges. It appears to be reasonable that the avoided cost therefore should be based either on the spot market price or the long-term price less the underlift charge. The utilities apparently simply assumed that the avoided cost of oil was less than gas when underlifts are taken into account and therefore assumed that their avoided fuel was natural gas. Given the current oil and gas mix and the current price relationships, such a simplifying assumption seems reasonable.

We cannot agree that oil should be presumed to be the incremental fuel when it is 10% of the daily use. Such a standard would be arbitrary. We are sympathetic to a more detailed analysis of marginal oil use in future proceedings in the determination of the marginal energy costs. The issue of whether oil or gas is the marginal fuel is complex and will depend upon specific circumstances. This issue is one that we would expect to arise in future pro-

ceedings to review the utilities's price offers, which we describe below.

Another issue in the proceeding is whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment. We agree with staff that the cost of warm up fuel cannot be included at this time since it is unclear that such fuel is avoided as a result of purchases from QFs.

Another issue relating to fuel costs is whether SDG&E should use its G-61 commodity rate for determining the avoided natural gas costs for its electricity utility generation. The staff and others recommend that the higher GN-5 rate be used, which is the rate established for pricing between SDG&E's gas and electric departments. The G-61 rate is the general commodity rate which SDG&E purchases all of its gas requirements.

We conclude that staff's position is correct. When the electric department of SDG&E purchases electricity from a QF, ratepayers avoid electric production with costs derived from the GN-5 rate for the purposes of calculating SDG&E's electric rates. By establishing QF prices using the GN-5 rate, ratepayers are indifferent between purchases from QFs and utility generation, consistent with avoided cost principles. To base prices on the G-61 rate would result in an underdevelopment of QF resources, leading to uneconomic use of natural gas in utility boilers. Use of the G-61 rate would also result in an inconsistent pricing system between QFs in Edison's and SDG&E's territory. Edison purchases gas from Southern California Gas Company at the GN-5 rate.

Utilities argue that fuel is not avoided when it is being burned to maintain spinning reserves. By definition, we agree. In the event fuel is being burned in the facility to allow it to be available for future periods, the availability of QFs does not allow the utility to avoid that fuel.

It is evident that the determination of the marginal fuel costs for utilities will remain a controversial subject and that the parties will want to be involved in reviewing the utilities determinations. As CMA points out, the dollars involved are large and will undoubtedly grow in the future as the QF market develops. It is important that we establish an understandable and balanced forum in which parties can review and comment on these prices.

We will therefore adopt the following procedure. In the case of PG&E and Edison, we will order the utilities to file prices for energy payments one month prior to the quarter in which the energy prices apply. These prices and a detailed description of the assumptions used to derive them should be filed with the Commission. In addition, the utility should make available this information to interested parties for their review. In the event either staff or the interested parties object to the proposed prices, a motion to adjust the price may be filed to the Commission. In the motion, the specific concern must be stated and a recommended resolution suggested. The Commission will decide what further action to take depending upon the nature of the motion.

In the event no action is taken by the Commission by the time a quarter begins, the utilities' prices will go into effect. These prices may be adjusted upward and applied retrospectively in the event the Commission later reaches a determination that the prices posted were too low. However, no downward adjustments will be made retrospectively to avoid pricing uncertainty for QFs.

SDG&E currently is establishing its prices three times a year in ECAC proceedings. We will continue this procedure. Like Edison and PG&E, SDG&E should spell out the assumptions used in deriving its numbers.

We expect utilities to forecast as accurately as possible their actual marginal operating costs for future quarters, including their expected fuel mix, and to provide their

assumptions to interested parties. We expect that as we reach decisions relating to various issues regarding price in the future, utilities will incorporate those decisions. Over time the utilities' procedures should become fairly understandable and routine. We have no doubt that parties will question utility determinations, and we expect to review them carefully. However, we do not intend to relitigate issues in proceeding after proceeding.

For this procedure to work, it is incumbent upon utilities to present their information clearly and understandably. QFs must be able to understand how prices are being determined to make intelligent investment decisions. We expect that utilities will keep all data relating to QF prices well organized in a central place to permit parties to review the calculations.

C. Adjustments to Energy Prices

A number of issues were raised in the proceeding regarding adjustments to energy prices for various purposes. We consider these issues in this section.

1. Avoided Transmission and Distribution Costs

Little or no evidence was presented in this proceeding demonstrating that QFs allow utilities to avoid transmission and distribution system costs. Therefore, none are included in the avoided cost payments filed by the utilities. We find this approach to be appropriate at this time.

2. Variable Operations and Maintenance Costs

There was general agreement that variable operating and maintenance costs should be included in the avoided cost determinations. However, PG&E and SDG&E include these costs in their energy payments while Edison includes them with its capacity payment. For consistency, we will order that these costs be included as part of the energy payment. In the regular price filings, the assumptions regarding the derivation of variable C&M should be included.

3. Line Losses

D.82-01-103 ordered applicants to "include costs or savings from line losses in the aggregate" (Ordering Paragraphs 6(a) and 8(e)). The Commission created an exception that line losses will be examined individually for "projects one MW or larger developed at sites remote from load centers."

The record in this proceeding indicates that this issue inadequately studied by the utilities to determine appropriate loss rates. PG&E's study does not differentiate between remote sites and other QFs, while SDG&E and Edison have not undertaken a study at all. In the absence of such a study, we will adopt a loss factor of 1.0 to be applied by all utilities for all QFs at this time. This resolution essentially assumes that QFs line losses are equal to utility plant losses, which seems reasonable lacking better information. We will also adopt the suggestion that loss factors be established for three voltage levels.

Additionally, we will adopt the staff position that studies be performed by utilities to determine the aggregate line losses of QFs. PG&E should report on this subject in 6 months and SDG&E and Edison in one year.

The record indicates that at this time adjustments for line losses for remote sites is beyond our current capabilities. We will therefore suspend the use of specific line losses for remote sites until the problem is better understood. As part of the studies required of utilities, we will ask for an analysis of how to identify remote QFs and how to reflect a different loss rate. Until such studies are performed, remote QFs will not have individual line losses adjustments.

PG&E suggests that individual line losses should be established. This approach would not comply with D.82-01-103. The individual determination of line losses would create great complexity and would very likely result in fre-

quent disputes between the utility and QFs. Aggregate line loss determinations are appropriate at this time.

4. Transformer Losses

An issue was raised about whether transformer losses should be included in the avoided cost payment, and if so, how that loss should be determined. The staff suggests an appropriate solution: simply place the meter on the utility side of the transformer, thereby automatically accounting for the transformer losses in the meter reading. We will adopt this recommendation. If a QF desires to have a meter on its side of the transformer, it may negotiate a transformer loss rate with the utility.

D. Refusal to Purchase and the Hydro Spill Rate

One of the more complex issues relating to energy payments regards the periods in which a utility may refuse to purchase from QFs or offer lower prices to reflect current conditions in the utility system. As described earlier, price is established for electricity purchases for a time period based on projected average marginal costs. The actual avoided costs incurred will vary throughout the period, varying around the average established.

There are certain conditions in which the actual avoided costs deviate so significantly from the average that special treatment may be warranted. In particular, D.82-01-103 found that when the utility actually incurs costs by purchasing energy from a QF (a "negative avoided cost" condition), the utility should have the right to curtail QFs. In D.82-04-71, the Commission also concluded that when a utility must spill water over its own hydroelectric facilities in order to purchase from QFs, a lower price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period.

Allowing utilities to pay lower rates or curtail customers unexpectedly creates significant complications for QFs because of unwieldy notification requirements and price instability. It is also very difficult to establish what the lower rate during periods of economy energy or hydro spill should be. For this reason we previously decided to very narrowly define the period and to include the expected economy energy purchases in the average rate for the entire period. What is lost in precision is gained in administrative workability and price certainty.

The parties in this proceeding suggest alternatives and refinements to this approach. Certain QFs suggest fixed limits on the number of hours that they can be curtailed or offered the lower hydro spill rate. A number of proposals were made to limit the applicability of curtailment and hydro spill conditions. Staff proposed that a 100-hour limit be established for curtailment and hydro spill conditions, while the IEP suggested that a total of 200 hours be applied to both. Staff suggested that in the event the QF is required to curtail more than 100 hours, it should be paid for the additional hours based on what it would have produced in event curtailment had not been invoked. Staff argues that it is unlikely that QFs would be curtailed for longer than 100 hours in any event, and the added certainty about being paid makes the provision worthwhile. Utilities, in general, oppose such restrictions in the contract, arguing that such provisions would be inconsistent with D.82-01-103 and could tend to overpay QFs.

Procedurally, we agree with the utilities that restrictions on the number of hours that curtailment and hydro spill conditions apply would be inconsistent with D.82-01-103 and D.82-04-071. Those decisions attempt to very narrowly define the conditions in which either term could he applied in order to reduce uncertainty for QFs. However, lacking any evidentiary basis, neither placed limits on the application of those provisions.

While we are sympathetic of the concerns of QFs that they must understand what the outside limit of the application of these provision could be, we have no evidentiary basis to determine what that limit should be. We will, therefore, order utilities to undertake studies to estimate the maximum probable limit for hydro spill and curtailment conditions likely to occur in future years in order to provide QFs with more certainty about the likelihood of those provisions being imposed. These studies should be submitted to the Commission and provided to parties within 3 months. Based on these studies, we will entertain proposals to modify D.82-01-103 to establish limits in the contracts for the refusal to purchase and the hydro spill conditions.

1. The 600-Hour Curtailment Option

Utilities have suggested that as an option, QFs be offered a curtailment provision that applies to periods of economy energy purchases and which includes a 600-hour annual limit. While we welcome and encourage such an offer being available as an option, the offer itself is outside the scope of these compliance proceedings. The standard offer should be based on the negative avoided cost and hydro spill conditions outlined in the original decisions. We will view the 600-hour curtailment provision option as a nonstandard contract for now because we have not reviewed the details of how the curtailment provisions would work or how they would affect the marginal energy prices. We support the concept, because it would provide greater pricing precision, and permit greater economy energy purchases.

2. Implication of curtailment on Firm Capacity Payments

An issue arose on how curtailment provisions relate to the firm capacity provisions. We conclude that QFs should be presumed to be available during curtailment periods and should be eligible for any output payments (even if not actually provided) since the QFs are being curtailed

by the utilities. We will therefore adopt the staff's suggestion that the contracts be modified to reflect these conclusions. This resolution comports with D.82-01-103 at page 81, which states that QFs signing firm capacity contracts should be paid for capacity during times of non-purchase.

3. Internal Use of Energy During Curtailment

Certain parties suggest that cogeneration facilities operating under simultaneous purchase and sale contracts be permitted to use energy internally in the event of curtailment. We reject this proposal. As staff points out, curtailment is likely to occur in periods of extremely low demand, and any further reduction in demand caused by internal use of electricity would likely reduce the value of curtailment and be costly for the utility. If a QF agrees to sell all of its output under simultaneous purchase and sale, the output should be subject to curtailment as for any other QF.

4. Notice Requirements

In order to assist QF planning, longer notice requirements for curtailment were suggested. D.82-01-103 established notice guidelines. We do not see any reason to change them here. Of course, utilities should give as much notice as possible of impending curtailment.

E. Price Floors and Levelized Payments

Suggestions were made in this proceeding to establish a price floor for energy payments and to levelize energy payments. Both of these suggestions are clearly outside the scope of these compliance hearings. The levelized payment option was addressed and rejected in D.82-01-103 (Pages 55-56) and the floor concept was not discussed at all.

If a floor price were established, some reduction of the energy price would be necessary to remain within the avoided cost concept. The floor reduces QF risks and cre-

ates the possibility that at some point the floor price paid might be above avoided cost. In return for this security, a lower price during the rest of the time is appropriate. We would encourage utilities to negotiate nonstandard contracts with floors or levelized payments if QFs are interested.

Further Modifications of Contracts

This decision is the first in these applications. We will issue later in 1983 another decision regarding other issues raised in this proceeding which may result in further modifications to these contracts.

QFs interested in signing contracts between now and the time of a final decision may be reluctant to sign until the Commission resolves the remaining issues. To relieve this uncertainty somewhat, we will give QFs who sign contracts between the effective date of this decision and the time a final offer stemming from these compliance hearings takes effect the opportunity to switch from the interim contract to the final contract. QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed.

Findings of Fact

1. The California Public Utilities Commission has a continuing interest in promoting the development of cogeneration and small power production facilities.

2. By D.82-01-103 in Order Instituting Rulemaking (OIR) 2, each electric utility was required within 45 days of the effective date of that order to file standard offers to be made to qualifying facilities for (a) as-available energy and capacity based on a short-run avoided cost methodology, (b) firm capacity based on a short-run marginal cost methodology, and (c) energy and capacity provided by QFs below 100 kW in size.

3. The offers required by D.82-01-103 were included in the applications which are the subject of this order.

4. Evidentiary hearings were held with respect to A.82-03-26 (PG&E), A.82-03-37 (Edison), and A.82-03-78 (SDG&E) to determine each of these utilities' compliance with the requirements of D.82-03-103 and other related orders in OIR 2; the reasonableness of provisions included in the utilities' offers, but not specifically addressed in the OIR 2 decisions; and the factual bases for the prices contained in each of the standard offers.

5. Consideration of issues recited in Finding 4 above for A.82-03-62 (Sierra Pacific Power Company), A.82-03-67 (Pacific Power & Light Company) and A.82-04-21 (CP National Corporation) have been deferred until the resolution of A.82-03-26, A.82-03-37, and A.82-03-78.

6. An additional issue properly addressed during the evidentiary hearing was the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revisions of the methodology for calculating a utility's as-available capacity payment is reserved for the utility's general rate case as specified in D.82-04-071.

7. For a decision to be issued in this proceeding prior to the end of 1982, only certain issues raised during the hearings and in briefs can be addressed. The remaining issues which are not resolved by this order will be considered as early as possible in 1983.

8. The issues chosen for consideration in this order relating to the utilities' capacity and energy payments will provide QFs with sufficient options to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

9. Payment for as-available capacity do not reflect any value for contract length, notice, termination or sanctions, since such provisions are not part of an as-available offer.

10. Firm capacity is viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions.

11. D.82-01-103 requires that (a) firm capacity payments reflect availability during system peak periods including such factors as dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies; (b) the value of each of these factors are to be calculated based on standards comparable to performance standards the utility would impose on its own plants; (c) the sum of each of these factors are to be included in the resulting capacity value; (d) a QF that exceeds operating standards normally expected of utility plants is to be able to earn a higher capacity payment; and (e) when resource limitations exist to reliable operations, plant capacity factor may be a better measure of reliable operation than availability.

12. Each of the utilities proposed a different approach to performance standards in their firm capacity standard offers.

13. Three general types of performance standards have been proposed in the utilities' filings—the first based on a level of peak period availability (PG&E's Option 1), the second based on a level of peak period output (PG&E's Option 2, SDG&E's Option 2, and Edison's single option), and the third requiring only a certain contract duration with no specific requirement for peak period output or availability (SDG&E's Option 1).

14. PG&E's Option 1 availability standard requires the QF to be dispatchable and available during emergencies and to maintain a certain level of peak period reliability. The option also imposes termination provisions for nonperformance and allows for scheduled maintenance.

15. As modified herein, PG&E's Option 1 is reasonable and in compliance with D.82-01-103.

16. PG&E's Option 2 output standard ensures reliable operation during peak periods and emergencies and, like Option 1, imposes termination provisions for nonperformance with an allowance for scheduled maintenance.

17. As modified herein, PG&E's Option 2 is reasonable and in compliance with D.82-01-103.

18. An 80% summer peak hour availability or output requirement under PG&E's Options 1 and 2 is reasonable and, with PG&E's revised reduction of payments provisions, is a sufficiently flexible measure of QF performance.

19. SDG&E's Option 2, an output-based performance offer, requires only a 50% level of output during all peak and semi-peak hours. This standard of performance is not commensurate with the utility plant avoided by QF purchases, which plant would have a higher level of peak period availability than 50%. Additionally, termination provisions are not imposed for failure to meet this standard.

20. SDG&E's Option 2 is not in compliance with D.82-01-103.

21. Edison's output-based performance standard fails to focus on peak-period availability, with a 50% performance level which is too lenient for the peak period and an emergency availability requirement which is too stringent and places too much emphasis on one aspect of peak period availability.

22. Edison's output based performance standard is not in compliance with D.82-01-103.

23. SDG&E's Option 1, which merely requires a contract commitment for a specified period with no peak period availability or output requirement, fails to reflect the performance standards for firm capacity offers required by D.82-01-103 and is not an option to purchase firm capacity as defined by that order.

24. SDG&E's Option 1 is not in compliance with D.82-01-103.

25. It is necessary for the utilities to refile their standard offers for firm capacity to conform to D.82-01-103.

26. To comply with D.82-01-103, all utilities must file standard offers with payments options based on both a QF's availability and energy production. PG&E's Options 1 and 2 serve as basic models for such options, as modified consistent with this decision.

27. To achieve overall compliance with D.82-01-103 and this order, the following principles should be incorporated in any utility's firm capacity standard offer:

a. Dispatchability must be defined to give a utility the right to require only increases, not decreases, in a QF's operation. Any other definition permits unwarranted and unreasonable interference with a QF's operations. Dispatchability need not be limited to on-and midpeak periods and emergencies if an approach like that used in PG&E's Option 1 is adopted.

b. Each payment option must provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance must consistently exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. A peak period availability or capacity factor in excess of 85% is a reasonable performance standard to require of QFs entitled to capacity payments in excess of 100% of the shortage cost proxy. An 80% reliability factor is reasonable for offers based on 100% of a utility's capacity costs. For an availability option which permits the higher

payment, a more certain measure of the QF's dispatchability is required than presently provided in PG&E's Option 1 in order to determine whether and at what level the QF actually exceeds the utility plant's operation.

c. PG&E's proposal with respect to the treatment of small hydro QFs whose payments are based on the five dry year average,but are experiencing a "drier" year than that average, is reasonable and should be adopted for all utilities with one modification. It is reasonable to permit hydro QFs to be paid during the "drier" year for the amount of capacity, if any, actually delivered to the utility. Capacity payments should resume at the contract price when hydro conditions once again reach the level used to determine the capacity rating.

d. Essential elements of a scheduled maintenance standard are a reasonable allotment of days for both routine maintenance and major overhauls, sufficient notice to aid utility system planning, and appropriate timing to avoid periods of greatest demand on the utility system. The scheduled maintenance allowance should be uniform for all utilities and should include all of the elements and requirements listed in the discussion of scheduled maintenance in this decision.

e. PG&E's revised approach for reducing payments under either its availability or energy output payment options for nonperformance is reasonable and should be adopted in all utility standard offers for firm capacity. This modified approach permits payments for capacity actually delivered during a 15-month probationary period with the potential of the orig-

inal payment level being reinstated or the QF's capacity derated at the end of the period depending on the QF's performance during he peak months. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. For the capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer should be included. No retroactive payment is necessary.

28. No provision is required in a firm capacity standard offer to permit as-available capacity payments during a start-up period. A QF seeking as-available capacity payments during the period before its firm capacity operations commence has the option of signing a short-term as-available capacity contract.

29. Each of the utilities properly responded to D.82-01-103 by including termination provisions in their firm capacity standard offers.

30. The utilities' termination provisions must be reasonable.

31. Termination provisions should encourage Qfs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole.

32. There is no reason for termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions.

33. Liquidated damage clauses, which limit damages to the amounts or formula prescribed in the clause and provide a party with advance knowledge of how the damages for termination will be calculated, are desirable and rea-

sonable for inclusion in every utility's standard offer for firm capacity.

34. It is reasonable for the liquidated damage clause to cover reimbursement of unearned capacity payments. The utilities' methods for calculating this reimbursement are reasonable, with the exception of the need for a uniform imposition of and standard for interest to be charged on the amount refunded.

35. The published Federal Reserve Board three months Prime Commercial paper rate (plus 50 points for SDG&E) is currently used to calculate interest on the utilities' various accounts and is a reasonable rate to apply to the repayments required of a QF which terminates its firm capacity contract with prescribed notice.

36. It is reasonable for the utilities to include liquidated damage clauses to cover the replacement costs associated with QF termination and to provide a reduction or elimination of those damages for a QF which gives the prescribed advance notice of its termination.

37. Each utility's standard offer for firm capacity must distinguish between those QF's terminating with prescribed notice, for which replacement damages are eliminated, and those which do not.

38. The specific notice required for termination should depend on the amount of capacity being terminated and may be utility-specific. The proposals of SDG&E and PG&E are reasonable; Edison should be required to prescribe a table similar to those proposed by PG&E and SDG&E varying the length of notice according to the amount of capacity being terminated.

39. For QFs terminating without prescribed notice, it is reasonable for all of the utilities to adopt PG&E's approach to calculating the damages to be added to the refund of overpayments, with one modification. The adopted

damage formula should reflect the time needed, as reflected in the notice table, to replace the lost capacity.

40. The utilities' calculation of damages can properly refer to future capacity prices.

41. Any requirement that a QF provide evidence of its ability to make potential termination payments is burdensome and unreasonable.

42. It is reasonable for each utility's firm capacity standard offer to include examples of the operation of its termination provisions.

43. A reduction in capacity should not result in a complete termination of an agreement; however, the termination provisions can be applied to the amount being reduced.

44. D.82-01-103 clearly provides for a limitation of one year to conversions from the simultaneous purchase and sale of energy to the sale of surplus only and for the application of termination provisions to QFs which undertake such a conversion.

45. It is reasonable for a utility to provide that a QF which undertakes the conversion referred to in Finding 44 above be subject to termination provisions only for the amount by which the contract capacity is reduced. This approach complies with D.82-01-103 and the application of termination provisions to capacity reductions. It should be used by each of the utilities.

46. Edison's inclusion of a notice requirement for the termination of an as-available capacity contract is unreasonable, is in conflict with D.82-01-103, and should be deleted. That decision specifically states that termination provisions are not appropriate for offers to purchase as-available power.

47. For the standard offers that are the subject of these compliance hearings, D.82-01-103 requires that avoided

costs be defined according to avoided short-run marginal costs. One component of this definition, avoided shortage costs, should be the basis for firm and as-available capacity payments.

48. In D.82-01-103 and D.82-04-071 the Commission adopted the capital costs of a combustion turbine as a proxy for shortage costs.

49. D.82-04-071 specified that as-available capacity payments are to be based on the full cost of the combustion turbine and that any refinements of this proxy would only be considered in future general rate cases.

50. Pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies which adjust the full combustion turbine shortage cost proxy for firm capacity payments.

51. Combustion turbine costs vary from one utility to another because of different financing costs, environmental requirements, and locational factors.

52. It is not reasonable for estimates of combustion turbine costs calculated at a given time to vary from one utility to another on the basis of general economic indices.

53. Edison's combustion turbine capital cost estimate of $415/kW for a January 1, 1982 plant on line date is reasonable.

54. Staff's 23-year plant economic life for the Edison combustion turbine estimate is reasonable and consistent with D.93887.

55. The escalation and discount rates used by staff for the Edison combustion turbine cost estimate are reasonable for the purposes of making that estimate.

56. Combustion turbine fuel inventory costs will escalate over the life of the plant and, for the purposes of the Edison combustion turbine cost estimate, 50% of the staff

oil escalation rate is a reasonable figure to use for fuel inventory escalation.

57. Edison's fixed administrative and general costs assumption is reasonable for purposes of calculating its combustion turbine cost estimate.

58. The increased system marginal operating costs resulting from the operation of the combustion turbine are more accurately reflected in avoided energy costs rather than avoided capacity costs.

59. SDG&E's 1982 combustion turbine capital cost estimate of $400/kW is reasonable for the purposes of QF pricing.

60. The SDG&E incremental cost of capital for the purposes of combustion turbine cost estimation is 15.5%.

61. Accurate combustion turbine costs for SDG&E include fixed administrative and general costs and staff's proposed escalation rates.

62. Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and plant economic life assumptions for combustion turbine cost estimation. These assumptions are reasonable.

63. The staff's 1982 generic combustion turbine capital cost of $450/kW is reasonable for the purposes of PG&E's QF pricing.

64. The escalation rates used by staff for the Edison and SDG&E combustion turbine cost estimation are also accurate rates for PG&E's combustion turbine costs.

65. A 15.5% incremental cost of capital is a reasonable assumption for combustion turbine cost estimation for PG&E.

66. An accurate PG&E combustion turbine cost will include a fuel inventory cost commensurate with that found reasonable for Edison.

67. Plant economic life, fixed operation and maintenance costs, and fixed administrative and general cost assumptions adopted for combustion turbine cost estimation in D.93887 are reasonable for the purposes of the combustion turbine cost estimation used for PG&E's QF pricing.

68. PG&E proposes to adjust the combustion turbine shortage cost proxy used to calculate firm capacity prices to reflect year-to-year variations in reserve margins, using PG&E's Energy Reliability Index (ERI) methodology.

69. The ERI methodology is an innovative approach to measuring shortage costs.

70. The ERI methodology is conceptually flawed and biased downward because it only allows for downward, and not upward, adjustments in the annual shortage cost proxy.

71. A precise shortage cost methodology will allow for upward adjustments in the equilibrium shortage cost when loss of load probabilities are greater than the target level.

72. The ERI methodology is conceptually flawed and biased downward because it treats uncertain factors such as plant start up dates and plant maintenance requirements in a deterministic fashion in estimating future shortage costs and reserve needs.

73. The absence of a sensitivity analysis casts doubt on the validity of ERI results.

74. PG&E utilized several erroneous input assumptions when it used the ERI methodology to derive firm capacity prices.

75. The accurate estimation of future shortage costs requires, to the extent it is feasible, the simultaneous rather than sequential consideration of load management program, utility resources, and QF power.

76. PG&E's proposed revisions of its firm capacity price methodology to use different load management assump-

tions in the estimation of future ERI numbers and to include retroactive capacity payments if Helms pumped storage plant and Diablo Nuclear power plant startup dates are not realized do not remove the bias in its ERI-based capacity prices.

77. For the calculation of firm capacity prices, SDG&E has proposed a shortage cost methodology that adjusts the combustion turbine proxy for year-to-year variations in reserve margins.

78. The SDG&E method is conceptually flawed because it only allows for downward adjustments in the annual shortage cost proxy, not upward adjustments.

79. The SDG&E method is flawed because it does not allow year-to-year increases in shortage costs to be followed by decreases in those costs.

80. In calculating firm capacity prices using its shortage cost method, SDG&E did not adequately allow for utility plant start up date uncertainty and included an unrealistic assumption about the 1982 availability of the SONGS 2 nuclear plant.

81. SD&E did not adequately substantiate its shortage cost methodology nor its input assumptions.

82. Given the same input assumptions, calculation of annual combustion turbine cost using either a plant deferral concept or a real economic carrying charge concept should lead to the same result and either is reasonable.

83. For the calculation of firm capacity prices, Edison has proposed a shortage cost methodology that bases 1982-85 shortage costs primarily on wholesale emergency capacity prices in the California Power Pool Agreement and secondarily on the Edison-California Department of Water Resources Contract and the principles of interconnected operations for the Navajo and Four Corners Power projects.

84. The wholesale contracts that Edison utilizes for 1982-85 firm QF capacity prices are complex energy and capacity exchange agreements that involve shared reciprocal services.

85. The fact that the price of emergency capacity in the California Power Pool has not changed since 1967 despite inflation and narrow reserve margins makes more likely the possibility that this agreement is a mutually underpriced reciprocal transaction that is not an accurate proxy for avoided shortage costs.

86. Edison did not adequately substantiate its claim that the emergency capacity price is the marginal resource avoided by firm QF capacity purchases.

87. The shortage cost methodologies for firm capacity prices proposed by PG&E, SDG&E and Edison in these compliance hearings are unreasonable.

88. Further hearings are required before more refined shortage cost methods can be adopted.

89. The capital cost of the combustion turbine is a reasonable proxy for shortage costs to be used for as-available and firm capacity prices.

90. It is reasonable that energy prices in the as-available, firm and less than 100 kW offers should reflect as nearly as possible a utility's marginal variable operating costs.

91. The current standard offers create unnecessary risks for QFs that energy prices in some future period might not be derived from a utility's avoided costs.

92. It is reasonable for each contract to include language that energy prices will be derive from the utilities' marginal variable operating costs, as approved by the Commission, throughout the life of the project.

93. It is not feasible to include an energy price formula in standard price offers.

94. It is reasonable for interested parties to have the opportunity to review and comment on the utilities' calculation of energy prices.

95. The determination of energy rates derived from the utilities' marginal operating costs is in an evolutionary stage. Refinements will emerge over time.

96. It is reasonable for utilities to use average year estimates of incremental heat rates, as determined in rate cases, for the derivation of energy prices until the Commission approves a more refined methodology.

97. Actual incremental heat rate and fuel use data filed regularly would be useful for the evaluation of future period energy prices.

98. It is reasonable that the input of new plants which affect the incremental heat rates be determined in an ECAC proceeding.

99. Projected energy prices are less precise than retrospective calculations, but provide more pricing certainty for QFs.

100. Current natural gas prices more closely reflect marginal operating costs than do historical costs.

101. Oil may be burned to control inventory or for testing without being a marginal fuel.

102. Fuel used to warm-up facilities is not necessarily avoidable.

103. SDG&E avoids natural gas at the GN-5 rate, not the G-61 rate.

104. Fuel is not necessarily being avoided when used to maintain primary reserves.

105. No evidence now exists that transmission and distribution costs are avoided by QF purchases.

106. It is reasonable that variable operating and maintenance costs be included explicitly in the energy price derivations.

107. Insufficient data exists on line losses at this time. A reasonable assumption is that losses are equal to the line losses of utility plants, thus implying an aggregate line loss factor for QFs of 1.0, except for secondary line losses, which can reasonably be assumed to be the utility's marginal line losses.

108. Until sufficient evidence is presented by utilities for the identification and valuation of losses from remote sites, the loss for all QFs for energy can reasonably be established at 1.0.

109. Transformer losses need not be established if the meter is on the utility side of its transformer.

110. Limited evidence exists on the maximum probable number of hours utilities might invoke either for refusals to purchase or hydro spill conditions.

111. Restricting the number of hours for hydro spill or refusal to purchase is inconsistent with D.82-01-102 and D.82-04-071.

112. The option to pay QFs a higher capacity payment in return for up to 600 hours of curtailment during periods of economy energy purchases, while desirable, is an issue outside the scope of these compliance hearings.

113. Internal use of energy by QFs on simultaneous purchase and sale during curtailment would reduce demand and possibly exacerbate load problems the utility is seeking to solve through curtailment.

114. A levelized or price floor energy option is outside the scope of these proceedings.

Conclusions of Law

1. The Commission should continue to encourage the development of qualifying cogeneration and small power production facilities.

2. The standard offers of PG&E, Edison, and SDG&E should include capacity and energy payment provisions which comply with our decisions in OIR 2 and are reasonable.

3. The capacity and energy payment provision of the utilities' standard offers for as-available capacity and energy and firm capacity should be modified in keeping with the discussion and findings of this decision.

4. To promote the signing of standard offers by QFs, this order should be made effective today.

ORDER

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, Pacific Gas and Electric Company (PG&E), Southern Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E shall file with the Commission's Docket Office an original and twelve copies of appropriate amendments to the standard offers included in Applications (A.) 82-03-26, 82-03-37, and 82-03-78 consistent with this decision and the ordering paragraphs contained herein.

2. Each utility's standard offer for firm capacity shall include the following requirements governing the performance standards to be applied to a qualifying facility (QF):

   a. Each standard offer shall include two payment options, one based on a QF's availability and the other based on a QF's energy production or output. PG&E's Standard Offer No. 2, Appendix C, Options 1 and 2, as modified in accordance with this order, shall serve as models for these payment options.

b. Dispatchability shall be defined to permit the utility to require only increases, not decreases, in a QF's operation. Dispatchability need not be limited to on and mid-peak periods and emergencies if the utility's payment option based on availability is similar to PG&E's Option 1.

c. Each payment option for firm capacity shall provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance shall consistently exceed a peak period availability or capacity factor of 85%. For offers based on 100% of a utility's capacity costs, a QF shall only be required to maintain an availability or capacity factor of 80%. For a payment option based on a QF's availability which permits the higher payment, each utility shall include in the standard offer a method of determining whether and to what extent the QF has been dispatchable at a level of 85% or better.

d. Each utility's standard offer for firm capacity shall provide that hydroelectric QFs, which have their capacity ratings based on the five dry year average, shall not have their capacity terminated or derated when their failure to meet minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average. During drier year conditions, a hydro QF shall be paid for the amount of capacity, if any, actually delivered to the utility. Capacity payments shall resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating.

e. Each utility's standard offer for firm capacity shall include an allowance for scheduled maintenance which provides as follows: (1) Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. (2) A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. (3) Reasonable advance notice to the utility of a scheduled outage shall be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. (4) Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months shall also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months. (5) No restrictions shall be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months). (6) Capacity payments shall apply during allowed outages for scheduled maintenance.

f. Each utility's payment options for firm capacity shall include provisions for the reduction of capacity payments in the event the QF fails to meet the minimum performance requirements. For both payment options, a probationary period not to exceed 15 months shall be adopted. For an availability option, like

PG&E's Option 1, if a QF fails to meet the minimum performance requirements, it shall continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility, that capacity shall be derated and subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced shall be subject to termination provisions. For an output option, like PG&E's Option 2, the QF shall earn capacity payments during the probationary period for the amount of capacity actually delivered. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity shall be derated to the monthly amount of capacity actually delivered during the peak months. The amount by which the QF's capacity is reduced shall be subject to termination provisions. Under both options, for capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer shall be included. The standard offer shall not include a provision for retroactive payments.

3. Edison's single payment option for firm capacity based on a QF's output and SDG&E's firm capacity payment Options 1 and 2 are not in compliance with D.82-01-103 and shall not be included in any standard offer for firm capacity.

4. The utilities' standard offers for firm capacity shall not include provisions for a QF to receive as-available ca-

pacity payments during the start-up period prior to the commencement of its firm capacity operations.

5. Each utility's standard offer for firm capacity shall include termination provisions which meet the following requirements:

a. Each utility shall provide for the reduction of capacity payments under the circumstances and in the manner provided in Ordering Paragraph 2(f) of this decision. Reductions in contract capacity shall not result in a complete termination of the contract but the amount by which the capacity is reduced shall be subject to termination provisions.

b. Each utility's standard offer for firm capacity shall require a QF terminating with prescribed notice to reimburse the utility for unearned capacity payments. Each of the utilities' methods for calculating this repayment, which are otherwise reasonable, shall include the requirement that interest be charged on the amount refunded. The interest charged shall be the published Federal Reserve Board three months' Prime Commercial Paper rate (plus 50 basis points for SDG&E).

c. The specific notice required for termination with notice shall vary depending on the amount of capacity being terminated. Tables similar to those in PG&E's and SDG&E's standard offers for firm capacity shall be included in each of the utilities' standard offers.

d. Each utility's standard offer for firm capacity shall require a QF terminating without prescribed notice to refund overpayments and to cover the utilities' replacement costs for the lost or reduced capacity. The offers shall in-

clude a liquidated damage clause calculating this additional payment for replacement costs similar to that prescribed in PG&E's Standard Offer No. 2, Appendix D (which reflects the actual notice given), with one modification. The adopted formula shall reflect the time needed, as indicated by the notice table, to replace the lost capacity. The utilities' calculation of their damages may refer to future capacity prices.

e. The utilities' termination provisions shall not require a QF to provide evidence of its ability to make potential termination payments.

f. Each utility's standard offer for firm capacity shall include examples of the operation of its termination provisions.

g. The requirements of D.82-01-103 with respect to conversions from the simultaneous purchase and sale of energy to the sale of surplus only shall be reflected in a utility's standard offer for firm capacity. Termination provisions shall only apply to the amount by which the contract capacity is reduced as a result of the conversion.

6. A standard offer for as-available capacity shall not include any notice requirement for termination.

7. The utilities shall file, along with the amendments to the standard offers ordered in Ordering Paragraph 1 above, firm and as-available capacity prices based on 100% of the capital costs of the combustion turbine, using the combustion turbine cost estimates adopted in this decision.

8. Edison's combustion turbine capital costs shall be based on the following assumptions:

a. A $415/kW 1982 combustion turbine cost.

b. Escalation and discount rates proposed by staff for Edison in this proceeding.

d. Fuel inventory costs proposed by staff with the exception that staff's inventory escalation rate shall be reduced by 50%.

e. Administrative and general costs which, on a levelized basis, shall be equivalent to 1% of the combustion turbine capital cost.

f. No differential fuel credit.

g. Fixed operation and maintenance costs to which staff and Edison have agreed in this proceeding.

9. SDG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $400/kW 1982 combustion turbine capital cost.

b. A 15.5% incremental cost of capital.

c. Fixed administrative and general costs commensurate with those adopted for Edison.

d. Fuel inventory costs, fixed operations and maintenance costs and plant economic life to which staff and SDG&E have agreed in this proceeding.

e. Staff's proposed escalation rates for SDG&E.

10. PG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $450/kW 1982 combustion turbine cost.

b. Escalation rates adopted for Edison and SDG&E.

c. A 15% incremental cost of capital.

d. Fuel inventory costs commensurate with those adopted for Edison.

e. Plant economic life, fixed operation and maintenance costs; and fixed administrative and general costs adopted for combustion turbine cost estimation in D.92887.

11. More refined shortage cost methodologies such as those proposed by the utilities in this proceeding for firm capacity payments shall be examined for possible application to QF pricing in SDG&E's and PG&E's current general rate cases and hearings on Edison's five-year energy price offer (A.82-04-46). Any revision in capacity prices that is adopted by the Commission because of this examination shall only apply prospectively to QFs that sign after the date of the orders in those proceedings.

12. Each utility's standard offer for energy shall reflect the following:

a. Each utility shall modify its as-available and firm capacity contracts, and its contract for QFs less than 100 kW to state that energy prices will be derived from the utilities' full avoided operating costs, as approved by the Commission, throughout the life of the contract.

b. Utilities shall file with the Commission's Docket Office beginning six months from the effective date of this order an original and twelve copies of their actual average incremental heat rates and fuel use quarterly, in the case of PG&E and Edison, and three times a year, in the case of SDG&E. The relevant models shall be modified to make whatever changes are required.

c. Utilities shall use the average year incremental heat rates, as determined in the most recent

rate case, for the derivation of energy prices until the Commission approves refinements.

d. The utilities shall file with the Commission's Docket Office by September 30, 1983 an original and twelve copies of a plan for estimating actual year incremental heat rates prospectively.

e. Utilities shall propose incremental heat rate revision in Energy Cost Adjustment Clause (ECAC) proceedings after new power plants come on line.

f. PG&E and Edison shall file with the Commission's Docket Office an original and twelve copies of prospective energy prices quarterly, 30 days prior to the date the prices take effect. Included with the filing shall be a clear, comprehensive description of how the prices were derived, in order to permit staff and interested parties to comment on them. Gas prices used for avoided energy costs shall be tentative and finalized using the price in effect on the effective date of the price change.

g. Absent Commission action, these price offers shall take effect on the scheduled effective date.

h. SDG&E shall file its energy prices three times a year in parallel with ECAC proceedings. Unless the Commission orders revisions, these prices shall become affective on the scheduled effective date. SDG&E shall provide a clear, comprehensive description of how the prices were derived.

i. SDG&E shall use the GN-5 natural gas rate for the determination of its energy prices.

j. Until revised line loss adjustment factors are approved by the Commission, PG&E's, Edison's, and SDG&E's transmission and primary distribution loss adjustments for energy shall be set at 1.0. Marginal line losses shall be used for PG&E's, SDG&E's, and Edison's secondary distribution loss adjustment for energy.

k. PG&E shall complete a revised line loss study in cooperation with staff and QF representatives and file an original and twelve copies with the Commission's Docket Office within six months of the effective date of this order. The study shall include a methodology for identifying and determining losses from remote sites.

1. SDG&E and Edison shall complete line loss simulation studies in cooperation with staff and QF representatives within two years and file an original and twelve copies of the results with the Commission's Docket Office.

m. Utilities shall include variable operating and maintenance costs in energy prices.

n. Utilities shall permit meters to be fixed on the utility side of a transformer. Transformer loss provisions shall be removed from standard contracts if a QF decides to put the meters on the utility side.

o. Offers to include 600 hours of curtailment in exchange for a higher energy rate the rest of the time, to levelize energy payments, or to adopt floors shall be viewed as nonstandard offers at this time, and outside the scope of these proceedings. Any such provisions shall not be included in standard offers.

p. Utilities shall delete any language which would reduce capacity payments for QFs during periods when they fail to perform under capacity contracts due to the utility refusing to purchase from the QF.

q. PG&E, Edison, and SDG&E shall file with the Commission's Docket Office within three months of the effective date of this order an original and twelve copies of studies estimating the average and maximum probable application of refusal to purchase and hydro spill provisions in future years.

13. The petitions for modification filed by CMA and Imotek, Inc. in OIR 2 are dismissed.

This order is effective today.

Dated December 30, 1982, at San Francisco, California.

I will file a concurring opinion.

/s/ LEONARD M. GRIMES, JR.
Commissioner

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

APPENDIX A
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LIST OF APPEARANCES

Applicants: Daniel E. Gibson, *David L. Ludvigson, Jo Shaffer*, and Ken D. Oleson, Attorneys at Law, for Pacific Gas and Electric Company; *Margaret A. Glodowski*, Attorney at Law, for Sierra Pacific Power Company; *Thomas F. Mulvaney*, Attorney at Law, for CP National Corporation; Stoel, Rives, Boley, Fraser and Wyse, by *Thomas H. Nelson*, Attorney at Law, for Pacific Power & Light Company; Margaret Sullivan and *Wayne P. Sakarias*, Attorneys at Law, for San Diego Gas & Electric Company; and *Eugene Wagner*, Richard K. Durant, Clyde E. Hirschfeld, Carol B. Henningson, and Frank J. Cooley, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Chickering & Gregory, by *C. Hayden Ames*, Attorney at Law, and *C. M. Laffoon*, for Geothermal Generation, Inc.; *Robert Burt*, for California Manufacturers Association; *James J. Cherry*, Attorney at Law, for Independent Power Producers Association; *Janet M. Curry*, for Department of Water Resources; *Robert Danziger*, Attorney at Law, for Sunlan Energy Corporation; *Michel Peter Florio* and Robert Spertus, Attorneys at Law, and Sylvia Siegel, for Toward Utility Rate Normalization (TURN); *James Helmich*, for Helmich Engineering; *Mark Henwood*, for Henwood Associates, Inc.; *Steven F. Hirsch*, Attorney at Law, and Laura B. King, for Natural Resources Defense Council, Inc.; Catherine Johnson, Gregg Wheatland, Kathy Weinheimer, and *Daniel Meek*, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Charles R. Farrar, Jr. and *Alan Cope Johnson*, Attorneys at Law, for Great Western Malting Company, Kerr-McGee Chemical Company, and Kimberly-Clark Corporation; *Jane S.*

Kumin, Attorney at Law, for Natomas Company and Thermal Power company; *John C. Lakeland*, for Mass-Production Systems; *W. J. Lawrence*, for Western Energy Associates; *Philip R. Mann*, Attorney at Law, for CMA Cogeneration Group and P. R. Mann & Associates; Graham & James, by Boris H. Lakusta, *David J. Marchant*, Thomas J. MacBride, and James B. Henly, Attorneys at Law, for Graham & James; *Wayne L. Meek*, for Simpson Paper Company; *Michael McQueen*, Attorney at Law, for Union Oil Company of California; Hanna & Morton, by *R. Lee Roberts*, Attorney at Law, for Hanna & Morton; *Donald G. Salow*, for Stone & Webster Management Consultants, Inc.; *Robert W. Schempp*, for Metropolitan Water District of Southern California; Petty, Andrews, Tufts & Jackson, by *Allen J. Thompson*, Attorney at Law, for California Independent Energy Producers; *Randall Tinkerman*, for Transition Energy Projects Institute; *Harry Winters* and *David A. Dorinson*, Attorney at Law, for University of California; *Robert M. Loch*, Attorney at Law, for Southern California Gas Company; *Donna M. Bronski* and Don Dier, for Department of General Services; *Gordon E. Davis*, William H. Booth and Richard C. Harper, Attorneys at Law, for Brobeck, Phleger & Harrison; Grattan, Gersick & Karp, by *John P. Grattan*, Attorney at Law, and *John V. Hilberg*, for Calcogen, Inc.; *Ken Haas*, Attorney at Law, for Windfarms, Ltd.; *Janice G. Hamrin*, for Independent Energy Producers Association; *Neil K. Holbrook*, for California Wind Energy Association; *Jeffrey E. Jackson*, and Thomas D. Clarke, Attorneys at Law, for Central Plants, Inc. and Pacific Hydropower Company; *Peter S. Reis*, Attorney at Law, for Texaco, Inc.; *Leonard L. Snaider*, Attorney at Law, and Robert Laughead, P.E., for the City and County of San Francisco; *Mark Farman*, for Resource Mangement International; *Carl*

E. Salas, for O'Brien Associates, Inc; *Jasper Williams*, Attorney at Law, and *William Swanson*, for Stanford University; *Jerry R. Bloom*, Attorney at Law, for Kimberly-Clark Corporation; Downey, Brand, Seymour & Rohwer, by *Philip A. Stohr*, Attorney at Law, for Federal Paper Board; Sutherland, Asbill and Brennan; Edward J. Grenier, Jr., Esq.; and Earle H. O'Donnell, Esq.; Hanna & Morton, by *R. Lee Roberts*, Attorney at Law, and William C. Prentice, for Ultrasystems, Inc.; *Ernest Lampert*, for United Energy Corporation; Brobeck, Phleger & Harrison, by Gordon E. David, William H. Booth, and *Richard C. Harper*, Attorneys at Law, for Imotek, Inc.; Terry Trumbull and *Robert F. Conheim*, Attorneys at Law, for the California Waste Management Board; *Peter S. Merrill*, for Cogenerating Power Company; *William S. Shaffran*, Deputy City Attorney, for John W. Witt, City Attorney, for the City of San Diego; *John Donald Eppick*, for County Sanitation Districts of Los Angeles County; Gordon E. Davis and *William H. Booth*, Attorneys at Law, for U.S. Windpower, Inc.; and *Matthew V. Brady*, Attorney at Law, *Doug Knight*, and *Vincent Schwent*, for themselves.

Commission Staff: *Brian T. Cragg* and *Lynn T. Carew*, Attorneys at Law, and *John Quinley*.

COMMISSIONER LEONARD M. GRIMES, JR., Concurring:

I concur in today's decision and write separately to express my views on projects which are designed to convert solid waste into electrical energy. I believe that these projects are of special value since they address the problem of public waste disposal in addition to providing all the benefits associated with alternative energy development.

Despite some efforts at recycling, we are still a throw-away society. Thousands of tons of waste are generated in our cities each day to the point where garbage may be the principal product of our urban centers. As the public officials responsible for "managing" our garbage are well aware, the economic and environmental costs of municipal waste are substantial.

Spurred on by landfills which are full and near-full and the difficulty of securing additional disposal capacity, a number of California cities have planned waste-to-energy systems ranging from 5 to 38 MW. These projects are among the most capital-intensive endeavors undertaken by local governments. Their success, in part will depend on the terms and conditions under which the cities will be paid for the power they produce.

While today's decision on the short term standard offers does not address waste-to-energy projects specifically, the decision should be of some assistance to these projects. The firm capacity output option may be attractive to waste-to-energy producers. The long term offer which is being developed may also be a useful option. Should non-standard contracts be necessary, I urge PG&E, SDG&E, and Edison to make every effort to sign reasonable contracts.

In my opinion, the risk to electric ratepayers from waste-to-energy projects is mitigated by the fact that such projects will be developed and operated by public agencies which are clearly interested in the long term operation of

their facilities. Also, attempts to shield electric ratepayers may ultimately prove to be futile. Risks not absorbed by electric ratepayers are simply shifted to garbage ratepayers. In many cases, they will be the same people responsible for generating the garbage in the first place.

/s/ Leonard M. Grimes, Jr.
LEONARD M. GRIMES, JR., COMMISSIONER

San Francisco, California
January 5, 1983

Decision 83-05-038 May 4, 1983

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982)

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for an Order by the California Public Utilities Commission Directing Edison to Purchase Power from Qualifying Facilities Based on a Standard Offer for Firm Capacity and Energy Based on Long-Run Marginal Costs (OIR-2).	Application 82-04-46 (Filed April 21, 1982)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power from Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariff Affecting Purchases from Qualifying Facilities.	Application 82-04-46 (Filed April 21, 1982)

INTERIM OPINION ON PROCEDURAL GUIDELINES

Introduction

The purpose of this decision is to establish a procedure to help resolve issues surrounding the "long-term resource plan based offer" (Standard Offer No. 5) ordered by the Commission in Decision (D.) 82-01-103, Order Instituting Rulemaking (OIR) 2, (January 21, 1982).

D.82-01-103 established comprehensive guidelines for sales of electricity from small power producers to utilities. The utilities were ordered to file five standard offers, each with different terms and conditions. The first four offers were all derived from short-run avoided cost methodologies that are conceptionally well understood, even though many difficult details needed to be worked out in compliance hearings.

The conceptual approach for development of the offer was not established for the long-run resource plan offer, and D.82-01-103 ordered utilities to make proposals for our review. After reviewing those offers, it became clear that evidentiary compliance hearings would lead to pro-

tracted conceptual cross-examination on how to pay small power producers entering long-term contracts for their value in deferring new utility capacity. Rather than starting with the utility proposals, we decided it would be preferable to define the alternatives, present some tentative proposals, and receive comments from parties. With this approach, parties' general positions could be better understood, and we hoped to establish a framework before going into detailed compliance hearings on specific utility offers filed within that framework.

So, we issued on November 18, 1982 a *Report and Request for Comments* (Report) which presented issues relating to Standard Offer No. 5 and tentatively proposed a framework for such an offer. The Report concluded that an interim offer should be based on a five-year forecast of utility projected short-run marginal costs, followed by prices in future years based on the energy and capacity costs of a new coal plant. The Report also proposed that payments escalate over the life of the contract to avoid complex termination requirements and that the small power producer should be given flexibility about the output commitment it will take for future years. We asked parties to comment.

Responses by Parties to Commission Report

By January 31, 1983 the Commission received comments on the Report from *18* interested parties addressing both substantive and procedural issues. The comments were uniformly helpful. The comments included constructive criticisms of the Report and imaginative alternative frameworks for a long-run offer. The Commission was presented good information on how to achieve a workable and useful long-term offer.

Most importantly, the comments indicated a broad consensus about the need to achieve the underlying purpose of the Standard Offer No. 5 which is to provide *greater price certainty* and to value the small power producers'

facilities consistently with utility resources. Pacific Gas and electric company (PG&E), for example, while disagreeing with much in the Commission's Report, strongly endorsed the Report's purpose:

> "It has become apparent that the currently available standard offers do not meet the needs of all QFs. One of the major reasons for this is the high degree of future price uncertainty in these offers which adversely affects the ability of some projects to obtain financing. . . . A well designed standard offer, which mitigates the uncertainty, is consistent with avoided cost principles, and balances ratepayer and QF risk would also be desirable." (PG&E comments, page 1.)

PG&E offers a new proposal for a framework to provide greater pricing certainty for small power producers. Similarly, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) express general accord with the purposes of the Report and make new proposals for a standard offer framework.

Parties representing small power producers also agree that a greater pricing certainty is necessary. Many point out that different facilities have different needs and possibly more than one long-term price offer should be available.

In addition to providing useful substantive information, the comments also suggest procedures for resolving this matter. There was significant difference of opinion among parties on procedure.

In our Report, we tentatively concluded "that resolution of *conceptual* and *policy* issues on what methodology is to be selected for the long-term offer does not require factual evidence, but can instead be more effectively decided through written comments and possibly oral presentations." (Commission Report, page 6.) We envisioned the

conceptual and policy issues being resolved through a rulemaking-type procedure, while the details of an actual offer would be resolved in subsequent compliance hearings.

PG&E and SDG&E strongly disagree with this procedure. They argue that evidentiary hearings are necessary before the conceptual issues in the standard offer can be resolved. PG&E argues that fairness and due process require that hearings be held. "[I]t would be highly undesirable to resolve these very complex issues without the benefit of evidentiary hearings." SDG&E expresses similar concerns, arguing that the proposed format by the Commission would lead to lengthy compliance hearings and uncertainty about the details of any final order.

SCE also suggests that evidentiary hearings are necessary:

> "Edison believes that these hearings can be handled expeditiously, and without undue delay, if the scope of such hearings is clearly defined. While we certainly agree that the public interest is not served by delay, neither is it served by an incomplete examination of the complex issues surrounding this topic, possibly resulting in the selection of a costing methodology that inaccurately values QF power to utilities and their ratepayers. Edison suggests that, upon receipt and examination of the comments submitted by the various utilities and interested parties, the Commission should submit a 'summary report' which delineates both the various proposals presented and the issues to be examined in an evidentiary hearing."

Many of the other parties commented on procedure. Pacific Energy Resources (Pacific Energy) agreed to hearings. While stating that the Commission report provides a helpful framework, it argues that:

> "[I]ssues raised in this report can be only fully explored by means of hearings before the Commission. At such time each interested party and each utility can present alternative methods of implementing the proposals outlined by the Commission in its report and can present alternative proposals for consideration." (Comments of Pacific Energy, page 10.)

The hearings contemplated by Pacific Energy appear to involve direct presentations to the Commission rather than substantial cross-examination.

Occidental Geothermal, Inc. suggests that "further cooperative exchange of ideas is necessary before QFs can formulate any comprehensive proposal." (Comments of Occidental Geothermal, Inc., page 6.) To that end, it proposes a sequence of workshops, evidentiary hearings on issues relating to project risks, briefs, a decision to order utilities to file an offer, followed by compliance hearings and a decision. Ultrasystems Incorporated also suggests evidentiary hearings on risk-related issues.

California Manufacturers Association basically supports our proposed procedure. It suggests workshops, briefs, followed by a Commission decision, followed by compliance hearings on utility filings. California Independent Energy Producers also supports our proposal.

Natural Resources Defense Council agreed that evidentiary hearings are not necessary, but suggested parties should have the opportunity to comment on other parties' comments. Similarly, the California Energy Commission suggests another round of comments after this Commission issues a more detailed rule.

1. Procedural Course and Guidelines

The decision on how to proceed with these consolidated matters is important. We are aware that some QFs are anxious to see this standard offer resolved soon in order

to decide whether to begin projects. Delay on completing this offer could arrest QF development. On the other hand, it is also important to explore these issues to assure that ratepayers' interests are protected.

There are two major alternatives developed by parties. One proposed by utilities would be to hold evidentiary hearings on all of these issues, followed by an order, followed by compliance hearings on utilities' offers. The second general proposal would be the receipt of further written and oral comments, followed by compliance hearings.

Either approach would be overly time consuming and would not necessarily serve the interests of parties. The comments of parties convince us that a long-term standard offer is highly complex, involving avoided cost methodology, performance requirements, and termination penalties. The issues will not be quickly resolved under either procedure. Because of the complexity, we also are not certain that a Commission-ordered standard offer will best meet the needs of parties. It is evident that there are many possible standard offers which could be developed that are consistent with avoided cost pricing principles.

We have decided, therefore, to use a different procedure to resolve this matter before holding any formal evidentiary hearings. We have decided to hold a negotiating conference to give parties an opportunity to work together toward a methodology for an interim long-term standard offer[s]. We noted earlier that there is widespread consensus among parties on the immediate need for the long-term standard offer to provide greater pricing certainty and to reflect the value of QFs in deferring new utility resources. While there are many ideas on how to translate this concept into an offer, we think with the mutual objective of a timely decision in mind, parties can reach an accord.

The negotiating conference, to be held before any formal hearings on the long-term offers, is intended to achieve three things: (i) establish an offer[s] which can be filed by utilities at least on an interim basis which will be supported by the parties; (2) an agreement on a proposal clearly identifying issues, if any, which require further proceedings; and (3) a better understanding by all parties of each other's positions on this complex matter. This, in turn, will lead to sharper definition of issues for any formal hearings in the future. The Commission, of course, will review and approve any interim offer, and address any proposals for additional proceedings. However, with substantial agreement among parties, we expect to be able to act more expeditiously.

The negotiating conference is a new procedure for the Commission. It should take place in a spirit of cooperation, not of adversarial posturing. Parties should come prepared for an intensive period of education, negotiation, and problem solving. Parties will all benefit by reaching an accord because an interim offer may then be quickly put in place.

We expect the negotiating conference to reach substantial agreement within one month after it commences in the middle of May. We will make as much time available during that month as is necessary for parties to work out an agreement. A tentative schedule for the conference will be presented by the administrative law judge (ALJ) on the first day of the conference. Parties will have an opportunity to review and discuss it. We expect the schedule to permit a thorough presentation of positions on the major issues by parties, followed by analysis, followed by negotiations to settle on an offer. The dynamics of the conference will, of course, depend upon the nature of the issues that need to be discussed.

The negotiating conference will being on May 23, 1983, and will last not longer than four weeks, with regularly scheduled meetings. Parties should send representatives

who can commit extensive time to this process and who can present positions and negotiate. We encourage QFs with similar interests to join and work together. We also encourage parties not only to send technical staff, but also be represented by those who can negotiate and make decisions. The staff will be represented by the Director of the Utilities Division, who will be supported by technical staff and staff counsel.

When the negotiating conference ends, the ALJ will issue a ruling which sets the time in which the three applicant utilities shall amend their applications with new standard offers. After a reasonable time for all parties to review and evaluate the amended standard offers, we will schedule a prehearing conference to evaluate the need for evidentiary hearings and, if they are required, their scope.

In order to encourage open participation at the negotiating conference, we will order that Rule 50 of our Rules of Practice and Procedure shall apply.[1] That will encourage a free and candid exchange of information, ideas, and alternatives.

2. Issues for Resolution

The comments in response to our Report provided many useful suggestions on defining a long-term contract and highlighted the issues that need to be settled. Two broad issues arise. First, what costs are avoided by long-term QF contracts? Second, a related, and workable pricing mechanism, with appropriate contract terms and conditions, must be established to pay the QFs for their contribution of providing electricity to avoid those costs. The nature of these payments may vary depending upon the conditions of operation agreed upon by QFs. Generally,

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[1] Rule 50 provides as follows: "(Rule 50) Facts Disclosed Privileged. Facts disclosed in prehearing conferences are privileged. Except by agreement, they shall not be used against participating parties, before the Commission or elsewhere, unless proved by evidence other than that employed in disclosing such facts."

the utilities devoted more attention to the first issue of costing, while QFs generally devoted more to the latter issue of pricing.

a. Costing Methodologies

The utilities generally support use of projected shortrun avoided costs (i.e., marginal running costs plus shortage value) for use in defining a long-run offer. Utilities assert that the criteria for determining whether a utility would add a new resource depends on whether the capital and operating costs of the proposed resource is less than the projected short-run avoided cost. Resources are added until the two are equal according to the rule of economic dispatch.

We agree that methodologies using projected short-run avoided costs and using the costs of new resources should produce the same results in theory. However, the problem is translating projected costs into QF prices. The utilities contend that the shortrun methodology can be used. The Commission's Report found that a coal plant would be a simpler proxy. Other parties expressed mixed views on the issue.

We expect this issue to be developed fully in the negotiating conference. Parties should have the opportunity to demonstrate clearly how to derive avoided cost numbers from their marginal cost methodology. A major criteria for consideration will be workability as well as theoretical validity. We are looking for *results*. We expect the negotiating conference to develop a consensus methodology that fairly reflects the long-term value of QF power that can be readily implemented through pricing.

b. Pricing

It is apparent from the comments that developing an avoid cost estimate represents only part of the problem of developing a standard offer. Equally difficult is trans-

lating those costs into a contract with prices, terms, and conditions.

QFs have different views on what the contracts should be like. Some QF representatives, particularly those with cogeneration facilities, are interested in fixing incremental heat rates in a contract, but not fixing total fuel prices, since a cogenerator's fuel price may fluctuate with the rates of serving gas utilities. Others would like more pricing certainty, including in some cases, levelized payments. Another area of difference involves performance requirements. Some QFs can produce reliably based on very stringent performance standards, others produce intermittently and seek a more flexible standard.

These differences explain why QFs want an array of standard offers; however, we must caution the parties that trying to devise a number of standard offers to accommodate all QF situations - and which do not result in favoring some QF technologies over others - will result in tremendous complexity and, of course, attendant delay.

We welcome some variety of long-term offer options, but we stress that all variations must be consistent with avoided cost principles. If levelized payments are proposed, for all or part of the contract term, we expect corresponding proposals to mitigate potential loss to the ratepayer resulting from nonperformance or overpayment.

c. Resolution of Issues Resulting From the Negotiating Conference

We expect that most of the issues can be resolved in the negotiating conference to permit an agreement on an offer that utilities should file on an interim basis. The agreement should include both a conceptual framework and a means of driving specific prices. We do not expect that parties will waive their rights to further proceedings in this matter. The long-term offer methodology is evolving, and it may be useful to further analyze the question later.

Therefore, in addition to a standard long-term offer, we solicit a consensus from parties on a procedure for further analysis of the long-term offers.

All parties should come to the negotiating conference with the list of issues which they see needing to be resolved, and should be prepared with proposals for resolution of issues. Staff will prepare and submit a comprehensive listing based on the comments for review already filed by parties. We expect the proposals to be offered with a spirit of compromise. Everyone will have the opportunity to present their proposals at the negotiating conference and make suggestions for improvements of other proposals.

INTERIM ORDER

IT IS ORDERED that:

1. A negotiating conference to be presided over by ALJ Alderson shall be held on May 23, 1983, at 9:30 a.m. at Hastings College of the Law, 198 McAllister Street, Room K, San Francisco. This conference shall continue over a four-week period, with the schedule to be set by the ALJ. It will not be reported by the Commission's Reporter, and the use of material disclosed during the conference will be governed by Rule 50 of the Commission's Rules of Practice and Procedure.

2. After the negotiating conference ends, the ALJ shall issue a ruling providing a time limit within which the applicants shall amend their applications with revised standard offers. Thereafter, a prehearing conference shall be scheduled to assess the need for hearings and define their scope.

3. This order shall also be served on the applicants and the parties served with D.82-12-120 in Application 82-03-26 et al.

This order is effective today.

Dated May 4, 1983, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

I abstain
/s/ PRISCILLA C. GREW
Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION

STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric and gas service. (Electric and Gas) U 39 M	Application No. 82-12-48

PETITION OF PACIFIC GAS AND ELECTRIC COMPANY FOR MODIFICATION OF DECISION NO. 83-12-068

Pursuant to Rule 43 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PGandE" or "Company") hereby petitions for modification of Decision No. 83-12-068 for the limited purpose of extending the capacity price table for Standard Offer No. 2.

Capacity prices for Standard Offers No. 2 and 4 were established in PGandE's 1984 General Rate Case in Table IV-4 at page 349 of Decision No. 83-12-068. Three clerical errors in this table were corrected by the Commission in Decision No. 84-05-101. Table IV-4 covered contracts with operating dates through 1988.

This table now needs to be updated. A QF signing a Standard Offer No. 2 has five years to become operational. Therefore, projects signing Standard Offer No. 2 in 1985 may come on line as late as 1990, although no capacity prices for 1990 were ever adopted by the Commission. Similarly, projects signing in 1986 may come on line in 1991. Therefore, to accommodate QFs who sign Standard

Offer No. 2 prior to January 1, 1987 (the effective date of PGandE's 1987 General Rate Case Decision), the Commission should extend the Firm Capacity Price Schedule to 1991.

Accordingly, PGandE requests that the Commission extend the firm capacity price table to include 1989-1991. The proposed prices which would be paid are shown in Attachment A.

The figures in Attachment A are based on the same assumptions used to develop Table IV-4 in Decision No. 83-12-068. They do not reflect any of the proposals which PGandE may include in its 1987 General Rate Case to be filed in December, 1985.

PGandE believes this Petition requests that the Commission merely perform a ministerial act. However, since capacity prices will be an issue in the 1987 General Rate Case, PGandE proposes that if this Petition is opposed and the Commission believes hearings are necessary, that the matter be deferred until the hearings in the 1987 General Rate Case. Since the basis for Attachment A is information developed over three years ago, there is no point in having hearings on such stale data.

Accordingly, PGandE requests that the Commission modify Decision No. 83-12-068 to include the capacity prices for projects commencing operation in 1989-1991 as shown in Attachment A.

Respectfully submitted,

HOWARD V. GOLUB
ROGER J. PETERS
MICHALE S. HINDUS

By _____
Michael S. Hindus

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 4, 1985

ATTACHMENT A

Firm Capacity Price Schedule

(Levelized $/KW-year)

Actual Operation Date (Year)	1	2	3	4	5	6	7	8	9
1989	115	119	123	127	130	134	138	141	144
1990	124	128	132	136	140	144	147	151	155
1991	132	137	141	145	150	154	158	162	166

10	11	12	13	14	15	20	25	30
148	151	154	157	160	163	176	187	195
158	162	165	169	172	175	189	200	209
169	173	177	180	180	184	202	214	223

Note: Based on the assumptions underlying Table IV-A in Decision 83-12-068.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second Applications of PACIFIC GAS AND ELECTRIC COMPANY for approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.	Consolidated Application No. 82-04-044 et al. and Application No. 82-03-026, et al. (Filed December 2, 1986)

And Related Matters.

RESPONSE OF FOSTER WHEELER POWER SYSTEMS, INC. TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR REHEARING OF DECISION 86-10-038

I. INTRODUCTION

On November 17, 1986 Pacific Gas and Electric Company ("PG&E") applied to this Commission for a rehearing of the Commission's Decision 86-10-038, issued October 16, 1986 (the "Decision"). In its application, PG&E repeatedly asserts that the firm capacity price table ("Table E-2") in the interim Standard Offer No. 4 contract (the "SO4") ends in 1987. PG&E argues from this assertion that if a seller under an SO4 fails to establish a firm capacity availability date ("FCAD") for its qualifying facility ("QF") by 1987, it forfeits all rights to receive any of the Table E-2 firm capacity prices, and must then negotiate new prices with PG&E. PG&E therefore contends that the Commission erred in extending the Table E-2 prices through 1990 in the Decision.

Foster Wheeler Power Systems, Inc. appears in this proceeding on behalf of its wholly-owned subsidiary, Foster Wheeler Martinez, Inc. ("FWM"), which will own and operate a 90 MW cogeneration facility (the "Facility") that is currently being constructed at the Tosco Corporation's ("Tosco") Avon Refinery in Martinez, California. Power from the Facility will be sold to PG&E pursuant to an executed SO4 (the "FWM SO4"). At FWM's request, the Table E-2 in the FWM SO4 was extended by PG&E through *1988,* using escalated prices based on the firm capacity price methodology previously adopted by the Commission. The actions of PG&E in extending this Table E-2 directly contradict its arguments in its Application for Rehearing, and demonstrate that those arguments are simply an attempt by PG&E to evade its obligations under executed SO4's.

FWM also filed an Application for Rehearing of the Decision on November 17, 1986. In that application, FWM argued that the Decision had erred in one limited respect, in that it changed the basis for calculating firm capacity payments under the SO4 from the FCAD to the Scheduled Operation Date ("SOD")*. FWM explained in its Application for Rehearing why this retroactive amendment of SO4 must be remedied.

In this Response, FWM wishes to point out: (i) that *all* parties to these proceedings agree that under the terms of the SO4, the FCAD determines firm capacity prices under Table E-2; and (ii) that PG&E's prior actions in

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*Under the SO4, the FCAD is the date on which a QF is *actually* ready to begin delivery of firm capacity. The FCAD therefore by definition cannot be specified in advance. The SOD is the *estimated* date of initial energy deliveries from a QF. The SOD is only a non-binding, estimated date of operation and may be changed at any time by a seller. *See* Application for Rehearing of Decision 86-10-038 by Foster Wheeler Power Systems, Inc. (on behalf of FWM) filed November 17, 1986 at 5-7 (hereinafter "FWM Application").

extending the Table E-2 in the FWM SO4 through 1988 undercut its arguments in its Application for Rehearing.

II. ALL PARTIES TO THESE PROCEEDINGS UNDERSTAND THAT THE FCAD DETERMINES FIRM CAPACITY PRICES UNDER THE SO4.

In its Application for Rehearing, FWM explained that the SO4 plainly states that firm capacity prices under Table E-2 are calculated on the basis of the FCAD, with the term "Firm Capacity Availability Date" displayed prominently in every Table E-2. FWM also pointed out that PG&E has repeatedly stressed these same clear terms in its previous filings in these proceedings.*

In its Application for Rehearing, PG&E again reaffirms this common understanding. PG&E explains that "Table E-2 provides prices based on avoided costs calculated at the time the obligation was incurred for firm capacity availability dates. . . ."** Other parties submitting filings to these proceedings make the same obvious point.***

All parties also recognize that the Decision would apparently alter these plain contract terms, and substitute the SOD for the FCAD in firm capacity price calculations,*

**See* FWM Application at 8-9.

***Application for Rehearing of Decision 86-10-038 by Pacific Gas and Electric Company, filed November 17, 1986 at 15 (hereinafter the "PG&E Application"). *See also id.* at 8, 11.

****See* Application of Independent Energy Producers Association for Rehearing of Decision 86-10-038, filed November 17, 1986 at 2-3; Application by Ultrapower, Inc. for Rehearing of Decision No. 86-10-038, filed November 17, 1986 at 4-6; Application for Expedited Limited Rehearing of Decision 86-10-038, filed by Basic American Foods on November 17, 1986 at 3-5.

**See e.g.*, PG&E Application at 1-2. PG&E characterizes the SOD as the date by which sellers "promised" to come on-line. As explained in the FWM Application, the SOD is only a non-binding estimate of a facility's on-line date, which may be changed at any time by a seller. No seller in any SO4 ever covenanted to be on-line by the SOD.

despite the fact that no party had ever argued for such a retroactive amendment of SO4 by the Commission. Not even PG&E attempts to defend this substantive amendment of SO4, even though the amendment would strip some QFs of the firm capacity prices specified in their contracts.** PG&E, like the other parties to this proceeding, is contesting the propriety of extending the price terms of Table E-2, not of *amending* the method for determining the *existing* firm capacity prices under the Table. For the reasons set forth in FWM's Application for Rehearing, the Commission must re-affirm that the FCAD is the basis for calculating firm capacity prices under Table E-2.

III. PG&E's OWN EXTENSION OF THE FWM SO4's TABLE E-2 THROUGH 1988 REFUTES ITS ARGUMENTS IN ITS APPLICATION FOR REHEARING.

In its Application for Rehearing, PG&E repeatedly asserts that Table E-2 does not contain any firm capacity prices for facilities establishing FCAD's after 1987.*** PG&E then argues that under the terms of Table E-2, post-1987 firm capacity prices are not available under SO4.

In making these assertions, PG&E is not only mistaken, but is also rather disingenuous, since PG&E itself extended the Table E-2 in the FWM SO4 through 1988 using escalated prices based on the firm capacity price methodology previously adopted by the Commission.* PG&E extended the FWM SO4's Table E-2 at the request of FWM and Tosco. The extension was not controversial,

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**For example, since the FWM SO4 contains a March 1, 1987 SOD, if the Facility comes on line in 1988, the Decision would limit it to 1987 firm capacity prices, rather than the 1988 prices specified in the contract and explicitly set out in Table E-2. The Decision would thus wipe out the firm capacity prices fixed for 1988 by FWM and agreed to by PG&E at the time they entered the FWM SO4.

***See PG&E Application at 4-7, 9.

*The FWM SO4 is included as Appendix A to the FWM Application.

since it was made solely in the interest of completeness, to make explicit what both parties already understood to be part of the contract.

PG&E's own extension of this one Table E-2 completely undercuts its argument that Table E-2 by its plain terms was intended to end in 1987, and that the escalated firm capacity prices derived from Standard Offer No. 2 and applied to the SO4s were deliberately omitted for years beyond 1987. It is fatally inconsistent for PG&E to claim that the Commission cannot "imply" Table E-2 firm capacity prices beyond 1987, when PG&E itself made precisely this implication in its extension of the FWM SO4's Table E-2.

PG&E's past treatment of Table E-2 should make it clear that PG&E's current arguments before the Commission are simply an attempt to evade its obligations under its executed contracts. Even if ultimately defeated, these arguments are threatening the continued financability of alternative energy projects by undermining the contractual certainty that the Commission sought to achieve in adopting the standard contract format.** The Commission should not countenance such behavior by a party under its jurisdiction.

IV. CONCLUSION

All parties to these proceedings understand that under the terms of the SO4, firm capacity payments must be calculated on the basis of the Firm Capacity Availability Date. No party ever requested that the Commission change these terms and no party has defended the Commission's substitution of the SOD for the FCAD in calculating firm capacity prices under Table E-2. For the reasons set forth in FWM's Application for Rehearing, this retroactive amendment of SO4 must be corrected.

**See Decision 86-10-038* at 5 (explaining that the "crux" of Interim Standard Offer No. 4 is the price certainty provided to QFs).

Further, it is a fact that PG&E on its own has extended Table E-2, using the very escalated rates that it now decries. PG&E's actions fatally undercut its current efforts to deny that firm capacity payments beyond 1987 were clearly established under the SO4 contracts. PG&E current arguments, no matter how legally unsound, have called into question the contractual certainty intended by the Commission and essential to the continued efforts to obtain financing for qualifying facilities. Because final resolution of these issues is necessary before qualifying facility financings may proceed, FWM respectfully requests that the Commission expedite its consideration of these matters, and promptly deny PG&E's Application for Rehearing.

Respectfully submitted,

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AMENDED IN ASSEMBLY MAY 25, 1983
AMENDED IN ASSEMBLY MAY 16, 1983

CALIFORNIA LEGISLATURE—1983-84 REGULAR SESSION

ASSEMBLY BILL No. 1942

Introduced by Assemblymen Davis and Hauser

March 4, 1983

An act to add Chapter 3.2 (commencing with Section 4217.10) to Division 5 of Title 1 of the Government Code, and to amend Section 2821 of, *and to add Section 228.5 to,* the Public Utilities Code, relating to energy conservation.

LEGISLATIVE COUNSEL'S DIGEST

AB 1942, as amended, Davis. Energy conservation contracts: *private energy producers.*

(1) Existing law does not expressly authorize and prescribe procedures for public agencies to develop energy conservation, cogeneration, and alternate energy sources at the facilities of the public agencies.

This bill would expressly authorize and prescribe procedures for public agencies, as defined, to develop energy conservation, cogeneration, and alternate energy sources at the facilities of the public agencies. It would authorize, subject to specified conditions, a public agency to enter into an energy service contract and a facility ground lease, or a facility financing contract and a facility ground lease, or an energy sale contract. It would also define terms for the purpose of these provisions.

(2) Existing law requires the Public Utilities Commission to approve and establish equitable charges to be paid by an electrical corporation which purchases electricity from

any private energy producer employing other than a conventional power source for the generation of electricity.

This bill would ~~require that any contract~~ *additionally authorize the commission to specify the prices, terms, and conditions* for the purchase or sale of electricity ~~executed by~~ *between* an electrical corporation and a private energy producer ~~pursuant to the rules of the commission governing these contracts~~ *and these prices, terms, and conditions, so specified, would* be considered reasonable and prudent for all purposes.

(3) ~~Existing law defines the term "electrical corporation" for purposes of the Public Utilities Act.~~

~~This bill would specifically exclude from that definition a corporation or person employing cogeneration technology or producing power pursuant to prescribed provisions.~~

(3) The bill would define the terms "qualifying small power producer," "small power production facility," and "qualifying small power production facility," and "qualifying small power production facility" as having the same meaning as specified federal statutes and regulations and would provide that a qualifying small power producer owning or operating a small power production facility is not a public utility subject to the commission's jurisdiction solely because of this ownership or operation.

Vote: majority. Appropriation: no. Fiscal committee: ~~no~~ *yes.* State-mandated local program: no.

The people of the State of California do enact as follows:

SECTION 1. Chapter 3.2 (commencing with Section 4217.10) is added to Division 5 of Title 1 of the Government Code, to read:

CHAPTER 3.2. ENERGY CONSERVATION CONTRACTS

4217.10. To help implement the policy set forth in Section 25008 of the Public Resources Code, and to extend

that policy to facilities of local governments, public agencies may develop energy conservation, cogeneration, and alternate energy supply sources at the facilities of public agencies in accordance with this chapter.

4217.11. The following terms, whenever used in this chapter, have the meanings given in this section, except where the context clearly indicates otherwise:

(a) "Alternate energy equipment" means equipment for the production or conversion of energy from alternate sources, such as solar, biomass, wind, geothermal, hydroelectricity under 30 megawatts, remote natural gas of less than one billion cubic feet estimated reserves per mile from an existing gas gathering line, natural gas containing 850 or fewer British Thermal Units per standard cubic foot, or any other source of energy, the efficient use of which will reduce the use of fossil or nuclear fuels.

(b) "Cogeneration equipment" means equipment for cogeneration, as defined in Section 218.5 of the Public Utilities Code.

(c) "Conservation measures" means equipment, maintenance, load management techniques and equipment, or other measures to reduce energy use or make for a more efficient use of energy.

(d) "Conservation services" means the electrical, thermal, or other energy savings resulting from conservation measures, which shall be treated as a supply of such energy.

(e) "Energy conservation facility" means alternate energy equipment, cogeneration equipment, or conservation measures located in public buildings or on land owned by public agencies, the energy from which shall be consumed in whole or in part by the public agency.

(f) "Energy service contract" means a contract entered into by a public agency with any person, pursuant to which

the person will provide electrical or thermal energy or conservation services to a public agency from an energy conservation facility.

(g) "Facility financing contract" means a contract entered into by a public agency with any person whereby the person provides financing for an energy conservation facility in exchange for repayment of the financing and all costs and expenses related thereto by the public agency. A facility financing contract may provide for the person with whom the public agency contracts to provide any combination of feasibility studies for, and design and construction of, all or part of the energy conservation facility in addition to the financing and other related services, and may provide for an installment sale purchase, *another form of purchase*, or amortized lease of the energy conservation facility by the public agency.

(h) "Facility ground lease" means a lease of *all, or any portion of,* land or a public building owned by, or under lease to, a public agency to a person in conjunction with an energy service contract or a facility financing contract. A facility ground lease may include, in addition to the land on which energy conservation facilities will be located, easements, rights of way, licenses, and rights of access, for the construction, use, or ownership by the person of the facility and all related utility lines, and off-site improvements related thereto.

(i) "Person" means, but is not limited to, any individual, company, corporation, partnership, public agency, state agency, association, proprietorship, trust, joint venture, or other entity or group of entities.

(j) "Public agency" means a county, city and county, city, district, community college district, school district, joint powers authority or other entity designated or created by a political subdivision relating to energy development projects, and any other political subdivision or public corporation in the state, except the State of Cali-

fornia, the California State University, and the University of California.

(k) "Public building" includes any structure, building, facility, or work which a public agency is authorized to construct or use, and automobile parking lots, landscaping, and other facilities, including furnishings and equipment, incidental to the use of any structure, building, facility, or work, and also includes the site thereof, and any easements, rights-of-way appurtenant thereto, or necessary for its full use.

4217.12. Notwithstanding any other provision of law, a public agency may enter into an energy service contract and a facility ground lease on such terms as its governing body determines are in the best interests of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least two weeks in advance, and if the governing body finds:

(a) That the anticipated cost to the public agency for thermal or electrical energy or conservation services provided by the energy conservation facility under the contract will be less than the anticipated marginal cost to the public agency of thermal, electrical, or other energy that would have been consumed by the public agency in the absence of those purchases.

(b) That the difference, if any, between the fair rental value for the real property subject to the facility ground lease and the agreed rent, is anticipated to be offset by below-market energy purchases or other benefits provided under the energy service contract.

4217.13. Notwithstanding any other provisions of law, a public agency may enter into a facility financing contract and a facility ground lease on such terms as its governing body determines are in the best interest of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least

two weeks in advance, and if the governing body finds that funds for there payment of the financing or the cost of design, construction, and operation of the energy conservation facility, or both, as required by the contract, are projected to be available from revenues resulting from sales of electricity or thermal energy from the facility or from funding which otherwise would have been used for purchase of electrical, thermal, or other energy required by the public agency in the absence of the energy conservation facility, or both.

4217.14. Notwithstanding any other provision of law, the public agency may enter into contracts for the sale of energy produced by the energy conservation facility at such rates and on such terms as are approved by its governing body. Any such contract may provide for a commitment of firm electrical capacity.

4217.15. The public agency may, but is not required to, base the findings required under Sections 4217.12 and 4217.13 on projections for electrical and thermal energy rates from the following sources:

(a) The public utility which provides thermal or electrical energy to the public agency.

(b) The Public Utilities Commission.

(c) The State Energy Resources Conservation and Development Commission.

(d) The projections used by the Department of General Services for evaluating the feasibility of energy conservation facilities at state facilities located within the same public utility service area as the public agency.

4217.16. Prior to awarding or entering into an agreement or lease, the public agency may request proposals from qualified persons. After evaluating the proposals, the public agency may award the contract on the basis of the experience of the contractor, the type of technology em-

ployed by the contractor, the cost to the local agency, and any other relevant considerations.

4117.17. The provisions of this chapter shall not be deemed to limit the authority of any public agency to construct energy conservation projects or to enter into other leases or contracts relating to the financing construction, operation, or use of alternate energy type facilities in any manner authorized under existing law.

4217.18. The provisions of this chapter shall be construed to provide the greatest possible flexibility to public agencies in structuring agreements entered into hereunder so that economic benefits may be maximized and financing and other costs associated with the design and construction of alternate energy projects may be minimized. To this end, public agencies and the entities with whom they contract under this chapter should have great latitude in characterizing components of energy conservation facilities as personal or real property and in granting security interests in leasehold interests and components of the alternate energy facilities to project lenders.

~~The term "clerical corporation" as defined in Section 218 of the Public Utilities Code shall not include any corporation or person employing cogeneration technology or producing power pursuant to Section 4217.12, 4217.13, or 4217.14.~~

SEC. 2. Section 228.5 is added to the Public Utilities Code, to read:

228.5. (a) The terms "qualifying small power producer," "small power production facility," and "qualifying small power production facility" have the same meaning as found in Section 796 of Title 16 of the United States Code and regulations enacted pursuant thereto.

(b) Notwithstanding any other provision of law, a qualifying small power producer owning or operating a small power production facility is not a public utility subject to the general jurisdiction of the commission solely because of the ownership or operation of the facility.

SEC. 3. Section 2821 of the Public Utilities Code is amended to read:

2821. The commission shall approve and establish equitable charges to be paid by an electrical corporation which purchases electricity from any private energy producer employing other than a conventional power source for the generation of electricity. ~~The commission may act in this regard on its own motion or on application of an electrical corporation or a private energy producer.~~

~~Any contract for the purchase or sale of electricity executed by an electrical corporation and a private energy producer pursuant to the rules of the commission governing these contracts shall be considered reasonable and prudent for all purposes.~~

The commission may also specify the prices, terms, and conditions for the purchase or sale of electricity between an electrical corporation and a private energy producer, and these prices, terms, and conditions, so specified, shall be considered reasonable and prudent for all purposes. The commission may act to specify these prices, terms, and conditions on its own motion or on application of an electrical corporation or a private energy producer.

SENATE COMMITTEE ON ENERGY AND PUBLIC UTILITIES

AB 1942 - Davis
As Amended 7-8-83
Government Code

Hearing Date: 7-12-83

Finance: Yes

Public Utilities Code

BACKGROUND

LOCAL AGENCIES

During recent years, as energy costs have risen and sources of income have been reduced, many public agencies have initiated energy conservation and development programs. Typical projects include the City of Santa Clara's co-generation project developed in conjunction with a local pulp and paper mill, the City of Modesto using purified gas from sewage sludge to power city vehicles, and the City of Fairfield's wind generation project.

There are two constraints which inhibit public agency development of alternative energy projects. One is a lack of funding and the other is a lack of specific authorization to develop alternative energy projects. Opportunities to work with private developers have been limited by uncertainty about legal authority to contract to develop projects on public property.

PRIVATE ENERGY PRODUCERS

Following the enactment of the federal Public Utility Regulatory Policies Act (PURPA) in 1978, the PUC in 1980 issued Order Instituting Rulemaking-2 (OIR-2). This investigation was begun for the purpose of establishing standards governing the prices, terms, and conditions of electric utility purchases from qualified private energy producers.

In January, 1982, the PUC issued a decision in OIR-2. The decision, among other things, ordered the major California electric utilities to file standard offers for power purchases based upon avoided cost principles. The offers are to be made available to all energy facilities that qualify under PURPA.

Besides the standard offer, contracts may be negotiated between the utility and an individual energy producer, taking into account specialized costs of that producer. Most contracts are of the negotiated type. Both negotiated contracts and standard offer contracts between a utility and a private energy producer are subject to PUC review for reasonableness at the time the utility seeks to include the contract costs in their rate base.

AB 1942, as amended 7-8-83, addresses two issues:

(1) The bill would authorize and prescribe procedures for public agencies, to enter into contracts with private investors to develop energy conservation, cogeneration, and alternate energy sources at public facilities.

The bill exempts public agencies and private investors producing energy pursuant to the provisions of the federal Public Utilities Regulatory Policies Act from being considered "public utilities" or "electrical corporations" and therefore being subject to PUC review.

(2) AB 1942 also provides that the PUC may, on its own motion or that of a utility or private energy producer, act to specify prices and terms for any purchase or sale contract entered into by a utility and a private energy producer. These contracts shall be deemed "reasonable and prudent" for all purposes.

COMMENTS

1. Supporters note that energy conservation and development projects at public facilities have provided signifi-

cant new energy sources and revenue to the government agencies involved.

2. PG&E, although in support of the bill, has suggested some technical amendments. They feel it would be helpful to clarify the definitions of the following five terms: a) alternate energy equipment; b) energy conservation facility; c) facility ground lease; d) energy; e) electricity.

3. AB 1659 (Farr), also before this committee, deals with local agency energy development through the formation of Community Energy Authorities.

POSITIONS

Support:

County Supervisors Association of California
League of California Cities
Pacific Gas and Electric Company

Neutral:

Public Utilities Commission

LB, AB 1942, Analysis
Hearing Date: 7-12-83

Supreme Court, U.S.
FILED
AUG 28 1987
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No. 87-178

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS & ELECTRIC COMPANY,
a California Corporation
Petitioner,

VS.

PUBLIC UTILITIES COMMISSION
of the
State of California,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of the State of California

RESPONDENT'S BRIEF IN OPPOSITION

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QUESTIONS PRESENTED

1. Does a state public utilities commission's interpretation of the terms of contracts, negotiated and approved more than three years earlier under the Public Utility Regulatory Policies Act of 1978 and the Federal Rules promulgated thereunder, raise a federal issue under the Act?

2. Do a state public utilities commission's decisions interpreting contract terms set to equal avoided cost pricing as provided under the Public Utility Regulatory Policies Act of 1978 and the Federal Rules promulgated thereunder, raise a federal issue as to whether the Act permits setting prices above avoided cost?

3. Do a state public utilities commission's decisions interpreting contract terms raise a federal issue under the Public Utility Regulatory Policies Act of 1978, where the state supreme court has decided, on the merits of the case presented, that the attack on these decisions is really a collateral attack on decisions issued three years earlier, and is therefore precluded by statute and precedent?

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No. 87-178

In the Supreme Court

OF THE

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OCTOBER TERM, 1987

PACIFIC GAS & ELECTRIC COMPANY,
a California Corporation
Petitioner,

VS.

PUBLIC UTILITIES COMMISSION
of the
State of California,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of the State of California

RESPONDENT'S BRIEF IN OPPOSITION

The Respondent Public Utilities Commission of California (Commission) respectfully requests that this Court deny the petition for writ of certiorari, which seeks review of the judgment of the California Supreme Court denying, without opinion, Petitioner Pacific Gas & Electric Company's (PG&E) petition for writ of review from three Commission decisions.

I
STATEMENT OF THE CASE

A. Overview

This case concerns the Commission's interpretation of an ambiguity in contracts between certain electric utilities (including PG&E) and nonutility electricity-generating qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA) (16 U.S.C.A. §§ 796 *et seq.*) and implementing regulations (18 C.F.R. Part 292).[1] The contracts are based on an offer standardized by the Commission pursuant to the requirements of PURPA and state law. The basic Commission-authorized agreement, known as interim Standard Offer 4 (interim SO4), implements PURPA provisions that require the respective utilities to buy QF-generated electricity.

Each utility offered its own version of interim SO4 as approved by the Commission. The specific terms at issue here pertained to all offers, but PG&E is the only utility which has had to be ordered to comply with its own agreement. The Commission reasonably interpreted the agreement, consistent with the agreement's purposes and the intent of the parties, as is made clear in the Commission decisions that originally approved the agreement and directed its development.

PG&E petitioned the California Supreme Court for review of the Commission's interpretation of interim SO4, as set forth in Decision (D.) 86-10-038 and modified in D.86-12-013 and D.86-

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[1] Congress enacted PURPA in order to encourage the development of alternative energy sources, thus reducing the country's dependence on fossil fuels; Congress found legislation necessary because electric utilities were reluctant to deal with alternative generators such as QFs. *FERC v. Mississippi* (1982) 456 U.S. 742, 750. In 1976, the California Legislature had passed the Private Energy Producers Act, Public Utilities Code §§ 2801 *et seq.*, in which the Legislature declared it "desirable and necessary" to require utilities to transmit QF power under certain conditions, in order "to encourage private energy producers to competitively develop independent sources of natural gas and electric energy not otherwise available. . . ." California Public Utilities Code § 2801.

12-104 on file herein as Appendices F, G, and H to PG&E's Petition for Writ of Certiorari (Petition). The California Supreme Court denied review, and PG&E filed its Petition with this Court.

B. History of the Development of Interim SO4

On January 21, 1982, the Commission issued D.82-01-103, 8 CPUC 2d 20, establishing guidelines for electricity sales from QFs to utilities. A primary guideline was "avoided cost," *i.e.*, the price paid to QFs was to approximate, as nearly as possible, the cost to the purchasing utility of obtaining an equivalent amount of energy and generation capacity from another source. Although the Federal Energy Regulatory Commission (FERC) regulations (FERC Rules) promulgated to implement PURPA authorize states to order utilities to pay more than avoided cost,[2] the Commission chose avoided cost as the standard to be applied in California. D.82-01-103 ordered utilities to file a series of standard offers, one of which was to be based on long-run resource plans. The latter, Standard Offer 4 (SO4),[3] was more complex than the others in its pricing provisions, payment options, *etc.*, and

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[2] The Preamble to the FERC Rules sets avoided cost as the price floor, saying: "While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of [QF] technologies. *However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal Law.*" Preamble to the FERC Rules, 45 Fed. Reg. 12214, 12221 [emphasis added]. The New York State Court of Appeals held, on the basis of this language, that PURPA does not preempt state regulation requiring utilities to pay more than avoided cost for QF power. *Consolidated Edison Company of New York, Inc. v. Public Service Commission of New York* (1984) 63 N.Y.2d 424, *appeal dismissed*, 470 U.S. 1075 (1985).

[3] Originally it was thought that there might be five standard offers, and the one at issue was referred to as "Standard Offer No. 5" in some of the earlier decisions cited. For clarity, we will refer to it throughout this filing as SO4.

D.82-01-103 ordered utilities to make detailed proposals for its development.

The Commission found the first proposals submitted for SO4 unsatisfactory and unworkable, and asked the parties to define issues and alternatives, and to comment on each other's submittals. On November 18, 1982, it issued its *Report and Request for Comments,* outlining issues surrounding SO4 and proposing a framework for its development. The comments were received by January 31, 1983, and from them the Commission derived its approach to SO4. This approach is set forth in D.83-05-038, issued May 4, 1983 (Appendix hereto.).

According to D.83-05-038, there was a broad consensus among the utilities, reflected in their comments, "about the need to achieve the underlying purpose" of SO4, "which is to provide greater price certainty and to value the small power producers' facilities consistently with utility resources." (Appendix, p. A-3.) The decision illustrates this consensus with a quote from the comments of PG&E:

> It has become apparent that the currently available standard offers do not meet the needs of all QFs. One of the major reasons for this is the high degree of price uncertainty in these offers which adversely affects the ability of some projects to obtain financing. . . . A well designed standard offer, which mitigates the uncertainty, is consistent with avoided cost principles, and balances ratepayer and QF risk would also be desirable.

(*Ibid.*)

The Commission found that the various approaches proposed by the parties would require long hearings and a Commission-determined SO4, and that "[i]t is evident that there are many possible standard offers which could be developed that are consistent with avoided cost pricing principles." (*Id.*, p. A-6.) The difficulty of predicting avoided cost through evidentiary hearings, even in the short term, was compounded by the instability of fuel

costs. (D.83-09-054, App. B to Petition, p. A-4).[4] Thus it might be years before a final SO4 could be developed through evidentiary hearings.

The Commission was concerned that, without an SO4 based on long-run avoided costs, the pressure for nonstandard contracts might increase as market volatility made it harder for QFs to finance Standard Offer contracts based on short-run avoided cost. "Also," the Commission said, "the long-term value of new QF capacity in the utilities' resource plans is not fully reflected by the existing standard offers which base prices on fluctuating short-run avoided utility cost (see D.82-01-103, p. 67). It is, then, in everyone's interest that a standard offer based on long-run avoided cost be adopted." (App. B to Petition, p. A-5)

Therefore the Commission held a negotiating conference so that the parties could work together to build a methodology for an interim long-run Standard Offer, convinced that, "with the mutual objective of a timely decision in mind, parties can reach an accord." (Appendix, p. A-6.) The interim SO4 would be used until a final SO4 could be developed through evidentiary hearings. The Commission believed that negotiations including all parties would result in a price that fairly approximated avoided cost, because utilities would not agree to terms in excess of their projected avoided cost, and QFs would not agree to terms below that. If PG&E had not accepted this direction, both as to

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[4] The decision anticipated the current dispute and resolved it, saying that "[s]ome may contend that prices fixed under long-term forecasts can, at least at times, be above actual avoided costs, and therefore both: (1) PURPA will be violated in that payments will exceed avoided costs, and (2) the ratepayers will pay too much. We think the proper view and test is whether over the course of a long-term contract, despite periodic swings in actual avoided costs both above and below a forecast, the prices reasonably compensate QFs for their value in avoiding a utility's costs, and keep the ratepayer economically indifferent to whether the generation was performed by the utility or a QF. *As long as there is equal likelihood that swings in actual avoided costs are both below and above the forecast, over the term of forecast based prices, we think the spirit and letter of PURPA are followed.*" D.83-09-054, App. B to Petition, p. A-6 [emphasis added].

methodology and as to result, it could have filed a timely application for rehearing of D.83-05-038.[5]

The negotiating conference was held from May 23 to June 24, 1983. At a second conference (July 22, 1983), the parties "indicate[d] whether the proposed standard offers should be allowed to go into effect by this Commission pending evidentiary hearings on the multitude of issues surrounding pricing QF power." (D.83-09-054, App. B to Petition, p. A-8.) The results of the negotiations were set forth in D.83-09-054, which authorized utiltities to make interim SO4 available to QFs. That offer includes the price tables which are at issue here. (See Appendix B to Petition.)[6]

These tables were meant to provide the price certainty which all parties had agreed was "the underlying purpose" of the

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[5] California Public Utilities Code § 1731 provides, among other things, that no cause of action arising out of any order or decision of the Commission shall accrue in any court to any corporation or person unless the corporation or person has filed an application to the commission for a rehearing within 30 days after the date of issuance of the decision. Cal. Pub. Util. Code § 1731. Section 1756 of the California Public Utilities Code provides that, to be timely, a petition for writ of review of a Commission decision must be filed with the California Supreme Court within 30 days of denial of rehearing, or within 30 days of the issuance of the decision on rehearing, if rehearing is granted. Cal. Pub. Util. Code § 1756. Under these provisions, PG&E has failed to raise any PURPA issue connected with D.83-05-038 or D.83-09-054 in a timely manner.

[6] Two types of payment are involved in utility purchases of QF power. One is the energy payment, which reflects the utility's variable costs (the most prominent of which is fuel) of generating each unit of electrical energy. Capacity payments reflect the reliability value to a utility system of having the potential generation of the QF's power plant available at any given time. In the methodology adopted by the Commission, capacity prices are based on the utility's cost of getting the same amount of equivalent capacity by building a combustion turbine (CT). The prices in question here relate to firm capacity (the amount of capacity a QF can guarantee), as-available capacity (unguaranteed capacity), and energy.

negotiating conference. They depend on a capacity pricing method which had been used for other Standard Offers, and energy prices based on projections of short-run marginal costs.[7] No new methodology was developed at that time.[8] The energy price tables contain several possible payment streams, all based on the assumption that fuel costs would rise over the term of the contracts. PG&E did not seek administrative review by filing an application for rehearing of the adoption of these tables in D.83-09-054.

The assumption of constantly rising fuel costs, on which D.83-09-054 prices were based, proved incorrect. These costs diverged from forecasts, making the agreed-on prices more and more favorable to QFs, until the Commission suspended the availability of interim SO4 to new QFs.[9] The suspensions did not affect the validity of interim SO4 contracts already signed at the time of the suspensions. In the end, SO4 was available only between September 7, 1983 and April 17, 1985.

D.83-09-054 said that the firm capacity price table[10] was to provide price certainty for the term of each contract (up to 30 years) with QFs which committed under interim SO4 to supply

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[7] "The capacity payments are determined and paid under the same terms as those in existing Standard Offers #1 and #2, for as-available and firm capacity, respectively." D.83-09-054, App. B to Petition, p. A-22. The methodology for developing capacity payments under SO2 was adopted in D.82-01-103, as modified in D.82-04-071 and D.82-12-120.

[8] Later, as intended, the Commission held months of evidentiary hearings to resolve issues surrounding the development of the final version of SO4, including a methodology for determining avoided cost in the long term.

[9] D.85-04-075 (April 17, 1985; App. E to Petition) suspended SO4's availability for all utilities and all payment options; previous decisions beginning with 84-10-098 (October 17, 1984) had ordered partial suspensions.

[10] PG&E's interim SO4 (Appendix K to Petition), the only interim SO4 at issue here, lists these prices in Table E-2 (firm capacity). PG&E's Table B-1 lists energy prices and Table D-2 as-available capacity prices. We will refer to the tables with PG&E's designations.

firm capacity, and which met the requirement that they begin delivering energy within 5 years of signing the contract. Because interim SO4 was not suspended until April, 1985, QFs which signed as late as that under the interim offer have until April, 1990 to begin deliveries. But the unmodified Table E-2 had firm capacity availability dates filled in only to 1987, leaving QFs which planned to begin operations later than that without the price certainty which was "the crux of interim Standard Offer 4." (D.86-10-038, App. F to Petition, at A-129.) The problem is much the same for Tables B-1 and D-2 (See Appendix K to Petition.), except that the agreement of the parties, ratified in D.83-09-054, intended price certainty for up to ten years for energy and as-available capacity.

C. Procedural Background to the Present Petition

In August, 1986, three QFs filed petitions for modification of D.83-09-054, asking the Commission to clarify the issue of Table E-2's extension, because PG&E refused to complete its tables through 1990 as the other California electric utilities had done. The QFs argued that the extension was implicit in their contracts, ministerial in nature, and required no evidentiary hearings. PG&E argued that QFs without the full term of price certainty originally built into the agreement ought to be paid "a reasonable price at the time of delivery," "by analogy to the Uniform Commercial Code as adopted in California" (D.86-10-038, App. A to Petition, p. 7.), rather than the price calculated at the time interim SO4 was developed, as provided in the FERC regulations, 18 CFR § 292.304(d) (2).

As PG&E concedes, the Commission has consistently refused to make retroactive changes to interim SO4, except in certain narrow circumstances not relevant here. (See D.83-09-054, App. B to Petition, ordering paragraph 1, pp. A-44-A-45.) Accordingly, the Commission refused to allow PG&E to change the terms of interim SO4 merely because conditions had changed since the adoption of the interim offer. In D.86-10-038 the Commission agreed with the petitioning QFs "that the extension is ministerial, given that we specified the appropriate discount rate in D.83-09-054, and the combustion turbine cost escalation factors are

already implicit in Table E-2." (D.86-10-038, App. F to Petition, p. A-134.)[11]

There, as here, PG&E argued that to complete Table E-2 would be to reform the contract retroactively, but the Commission said that "this theory collapses because we are *not* supplying missing terms but rather construing the express terms to give them clear and logical effect." (*Id.*, A-135.) The Commission found, among other things, that:

> 3. Interim Standard Offer 4 is the result of a negotiating conference at which the parties agreed on a series of energy and capacity price schedules. *The purpose of the schedules is to provide a contract with price certainty equal to or greater than that provided to QFs under Standard Offers 1, 2, and 3.*
>
> 4. The intent of Table E-2, and other provisions in interim Standard Offer 4 regarding firm capacity QFs, is to establish a payment schedule for firm capacity calculated for the term of the contract at the time the contractual obligation is incurred. This treatment of firm capacity pricing is identical to one of the payment options available to firm capacity QFs under Standard Offer 2.
>
> 5. Extension of Table E-2, as requested by petitioners, is essentially ministerial.

Id., p. A-137 [emphasis added].

Accordingly, the Commission ordered that PG&E complete its Table E-2 to include the years 1988 through 1990. However, D.86-10-038 provided that the ordered escalation of Table E-2 prices according to its original methodology should be limited to those QFs with firm capacity availability dates (erroneously called "on-line dates" in the order) during those three years, and

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[11] The Commission noted "that PG&E itself (in a petition for modification of D.83-12-068) has argued that extension of a firm capacity price schedule for purposes of Standard Offer 2 constitutes a 'ministerial act.' Not surprisingly, PG&E has asked to withdraw that petition. We have not as yet ruled . . . as the petition was filed in another proceeding (A.82-12-48)." (D.86-10-038, App. F to Petition, fn. 11.)

that "QFs who come on-line later than the date specified in their contracts but consistent with the five-year deadline should retain their original firm capacity payment schedule but are not entitled to escalation." (D.86-10-038, App. F. to Petition, p. A-138.)

Applications for rehearing of D.86-10-038 followed, asking the Commission (1) to clarify its erroneous use, in D.86-10-038, of the term "on-line date" to refer to the date determining the firm capacity price; and (2) to clarify "what should be done about prices that appear to come within the 'fixed price period'[12] of a given QF but that presently do not have prices indicated in the relevant payment schedules [Tables B-1 and D-2] in PG&E's interim SO4." (D.86-12-013, App. G to Petition, p. A-142.)

The Commission chose to address only the first issue in D.86-12-013, and to devote more time and consideration to the second issue for decision at a later date. D.86-12-013 confirmed that the intent of the parties had always been to use the firm capacity availability date as the determining date for the firm capacity prices under Table E-2 (which itself specifies "Firm Capacity Availability Date" as the operative date. App. K to Petition, page A-238.), and that the Commission's inappropriate use of the term "on-line date" had been unintentional.

The second issue, that of the completion and escalation of Tables B-1 and D-2, was considered in D.86-12-104. The Commission modified D.86-10-038 to extend them, finding that price certainty was intended for these tables as well as for E-2, and that without the extension, many QFs would not receive the full "fixed price period" of up to ten years intended under interim SO4. (See footnote 12, above.) The Commission declined to escalate prices

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[12] "*Fixed price period*—The period during which forecasted or levelized energy prices, and/or forecasted *as-delivered capacity* prices, are in effect; defined as . . . the first ten years of the *term of agreement* if the *term of agreement* is anywhere from 20 through 30 years." App. K to Petition, p. A-197 (emphasis in original). It is difficult, in the face of this language, to see how PG&E can argue in good faith that it did *not* intend to assure ten years of price certainty for energy and as-available capacity for QFs with long-term contracts.

in these tables in the extended years, however, distinguishing them from Table E-2 as follows:

> [Table E-2] is merely an expression of the values of the agreed-upon price proxy, the cost of a combustion turbine (CT), carried over all applicable years. The change due to escalation was thereby made ministerial. Tables B-1 and D-2, on the other hand, are based on negotiations between the parties, which cannot be replaced without long and complex hearings for the sole purpose of adopting a workable methodology. Such hearings for the purpose of determining the increment or decrement for three years' worth of pricing would be of far more cost than benefit to all concerned.
>
> . . .
>
> The simplest method of completing the ten years of price certainty is to carry the last value, that of 1997, forward over the next three years. This method at least provides price certainty and sets the price at the last negotiated price level; if the price is too high or low, then the harm suffered by either the utility or the QFs will thus be minimized.

(D.86-12-104, App. H to Petition, pp. A-146-A-147.) The Commission went on to note that there had been some changes in the Tables already negotiated between the utilities and the QFs, but made it clear that the decision was not meant to affect such agreements, and declined to discuss them further, saying,

> We think it is clear that everyone's efforts are best put to use in this proceeding on refinements to resource planning, capacity valuation, and updating for *prospective* application to QF/utility transactions. It is not the business of this Commission or the utilities to adjust for current perceptions of oversupply by harsh dealing toward QFs already under contract.

(*Id.*, App. H to Petition, p. A-147, emphasis in original.) The Commission's refusal to grant PG&E such a retroactive adjustment of its interim SO4 contracts was consistent with prior decisions. Having failed to convince the California Supreme Court, PG&E now seeks to convince this Court that the contract

problem presented is a federal question involving the interpretation of PURPA.

II
ARGUMENT

A. The decisions below raise no federal issue under PURPA because they interpreted not PURPA but standard contracts negotiated and approved more than three years earlier as in compliance with the Act.

PG&E bases its jurisdictional claim on Title 28, United States Code § 1257, subdivision (3). PG&E argues that the case presents a federal issue regarding the interpretation of PURPA, saying that the Commission is attempting to require PG&E to pay QFs more than PURPA authorizes for energy and capacity. In fact, the prices at issue were negotiated by PG&E in 1983 and adopted by the Commission in that year without challenge by PG&E. The decisions to which PG&E now objects were mere interpretations necessary to correct a gap in the contracts. This case presents no federal issue and therefore is inappropriate for certiorari.

The crux of interim SO4 is to assure price certainty to QFs, with prices set according to the year in which each QF starts operating. However, the price tables originally appended to the offer were not filled in for three of the years needed to accord some QFs the full period of price certainty stated in the offer. The decisions of which PG&E now seeks review corrected this ministerial error, and did not in any way alter the basic contracts which PG&E negotiated in 1983, and which PG&E now, for the first time, claims to be in violation of PURPA.

The Commission decisions at issue did not interpret PURPA; that interpretation was made in 1983 in D.83-05-038 and D.83-09-054. The three decisions attacked in the Petition merely interpreted the contracts adopted by the 1983 decisions and corrected ministerial errors.

PG&E argues that the latest decisions set "new" prices exceeding avoided cost under PURPA and without any evidentiary

hearings. There were no hearings for the correction of errors, first, because the contract in question was *interim* SO4, the offer intended to implement PURPA temporarily so as to permit the parties to hold the extensive hearings necessary to determine avoided cost with the greatest possible precision; and, second, because the errors were minor and correctible, according to a mathematical formula in Table E-1 and on a minimal-harm basis for Tables B-1 and D-2.

The extension of these tables did not constitute adoption of "new" prices, because the tables prior to the corrections did not contain any prices at all for QFs with firm capacity availability dates falling within the last three years of interim SO4's availability. Under PG&E's logic, any payments for energy or capacity during those years would be "new" prices; the only way to avoid "changing" the original contract would be for the QFs to produce electricity and deliver it to PG&E without any payment at all.

Since the prices are not "new," but mere extensions of the prices negotiated by PG&E itself in 1983, it was unnecessary either to interpret PURPA or to hold hearings to determine avoided cost to extend the tables. The decisions interpreted no more than PG&E's interim SO4 contract in the light of the intent of the parties at the time the contract was negotiated and approved. PURPA was therefore not involved in these decisions, and its interpretation is irrelevant to them. Because PG&E's entire jurisdictional argument is based on the premise that the interpretation of § 210 of PURPA has been drawn in question, and because it is clear that PURPA is not involved, it is also clear that the requirements of 28 U.S.C. § 1257 are not satisfied, and that this case is not an appropriate one for granting of a writ of certiorari.

B. The decisions below raise no federal issue under PURPA because, even if avoided cost under PURPA were an issue in this matter, the prices in question were set to equal avoided cost.

PG&E argues that the prices for energy and capacity under its interim SO4 contract exceed avoided cost and therefore violate PURPA. This is untrue; D.83-09-054 set payment schedules for

firm capacity, as-available capacity, and energy to be equal to avoided cost as calculated at the time the obligation was entered into by PG&E. This action was well within the authority granted to the Commission under PURPA and the FERC rules. (See 18 C.F.R. § 292.304 (d) (2).) The fact that PG&E's *current* projections of avoided cost makes prices set in 1983 seem high cannot retroactively affect those calculations.[13]

PG&E's arguments concerning avoided cost are nonsensical. The FERC Rules and case law establish that avoided cost is the lowest permissible price for QF power. (See footnote 2, above.) If PG&E's interpretation of PURPA and the Rules were correct, and avoided cost were also the ceiling price (Petition, pp. 15-16), the Commission could set no price at all that was not *exactly* equal to avoided cost, as calculated not only at the time the contract is entered into but also at any point during the life of a 30-year contract. This result is illogical, as the exact *current* value of avoided cost necessarily shifts in response to volatile fuel prices. It is possible that, by the end of the term of the interim SO4 contracts in question, the prices at issue will be equal to, or lower than, the long-run avoided cost considered over the life of the contracts.

Yet even if PG&E's interpretation were correct, it would be beside the point, because the Commission in D.83-09-054 set prices to equal avoided cost as calculated at the time interim SO4 was created, as determined and agreed to by *all* parties, including PG&E, according to their best projections. (See discussion of the history of interim SO4, above.)

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[13] PG&E's dire predictions of billion-dollar excess payments are based on nothing more than projections, just as the prices now at issue were based on projections PG&E made in 1983. There is no way to be certain that oil prices will remain as low as they are now for the duration of the contracts in question. It is still conceivable that, before QF contracts under interim SO4 have run their terms, the prices will again be as advantageous to PG&E as they were when PG&E negotiated them in 1983.

C. The decisions below raise no federal issue under PURPA because, even if the Commission's 1983 decisions had set prices above avoided cost, PG&E is precluded by statute and caselaw from collateral attack at this late date.

Even if there were a federal PURPA issue involved, PG&E is precluded from making that argument now because it failed to raise the issue in a timely manner.

It is clear that PG&E accepted the Commission's authority to set avoided cost by the methodology of D.83-05-038 and with the contracts approved in D.83-09-054. Otherwise, PG&E would have challenged those decisions by applying for rehearing, and, if denied, petitioning the California Supreme Court for review before bringing the matter to this Court. (See footnote 5, above.) It did not do so, because the decisions were well within the Commission's authority, and because, at the time, the prices set were in accord with PG&E's own projections of avoided cost.

California Public Utilities Code § 1709 provides that, "[i]n all collateral actions or proceedings, the orders and decisions of the commission which have become final shall be conclusive." Cal. Pub. Util. Code § 1709; *Sale v. Railroad Commission* (1940) 15 Cal.2d 612, 616; *People v. Western Air Lines, Inc.*, 42 Cal.2d 621, 630, *appeal dismissed* 348 U.S. 859, 860 (1954); *Napa Valley Electric Co. v. Railroad Commission* (1920) 251 U.S. 366, 371-373; *Southern Pacific Transportation Co. v. Public Utilities Commission*, 716 F.2d 1285, 1289-1291 (9th Cir. 1983), *cert. denied*, 444 S.Ct. 1908 (1984).

Thus, D.83-05-038 and D.83-09-054 have become final on the issue of the price tables which PG&E contests here, and their findings of fact and conclusions of law have become conclusive, through the failure of any party to challenge them within the time provided by the statutes. Therefore, even if PG&E were to challenge those decisions directly now, the conclusiveness of the findings and conclusions which support them would preclude any relief through review in the courts. The Commission pointed out PG&E's lateness in its arguments before the California Supreme Court, which denied PG&E's petition. Such a denial, even without opinion, acts as a decision on the merits, both as to the law

and the facts presented in the review proceedings, under the rule of *People v. Western Air Lines* (1954) 42 Cal.2d 621, *appeal dismissed* 348 U.S. 859.

CONCLUSION

PG&E negotiated its interim SO4 in 1983 under PURPA's requirements and under this Commission's direction. At the time, the parties intended to provide price certainty for the full term of the contract for firm capacity, and up to ten years of price certainty for energy and as-available capacity. The prices, based on long-term value to the utilities of the capacity and energy bargained for, were negotiated by the parties, including PG&E, on the assumption, among other things, of constantly rising fuel costs over the term of the contracts.

Since the adoption of the contracts, fuel prices have plummeted and the prices in interim SO4 are no longer as attractive to PG&E as they were in 1983, when PG&E negotiated them and the Commission approved them. PG&E has asked the Commission and the California Supreme Court for retroactive reformation of the contracts, and its requests have been denied. PG&E now asks this Court to review the Commission's refusal to make such retroactive changes.

The Commission is completely within its authority to continue to refuse to make these changes. The evidence plainly shows that the Commission's decisions interpreting PURPA were made in 1983, without challenge by PG&E; that the 1983 decisions were made in full compliance with PURPA and the FERC rules; and that the decisions now appealed from did no more than interpret the interim SO4 contracts approved more than three years earlier. There is no federal issue involved in this matter, and, had there been one, it would have been precluded by PG&E's failure to make timely appeal. Therefore, certiorari is inappropriate, and the petition should be denied.

Respectfully submitted,

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Appendix A

Decision 83-05-038 May 4, 1983

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application 82-04-44
(Filed April 21, 1982)
Second Application of Pacific Gas and Electric Company for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.

Application 82-04-46
(Filed April 21, 1982)
In the Matter of the Application of Southern California Edison Company for an Order by the California Public Utilities Commission Directing Edison to Purchase Power from Qualifying Facilities Based on a Standard Offer for Firm Capacity and Energy Based on Long-Run Marginal Costs (OIR-2).

Application 82-04-47
(Filed April 21, 1982)
In the Matter of the Application of San Diego Gas & Electric Company for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power from Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariff Affecting Purchases from Qualifying Facilities.

INTERIM OPINION ON PROCEDURAL GUIDELINES

Introduction

The purpose of this decision is to establish a procedure to help resolve issues surrounding the "long-term resource plan based offer" (Standard Offer No. 5) ordered by the Commission in Decision (D.) 82-01-103, Order Instituting Rulemaking (OIR) 2, (January 21, 1982).

D.82-01-103 established comprehensive guidelines for sales of electricity from small power producers to utilities. The utilities were ordered to file five standard offers, each with different terms and conditions. The first four offers were all derived from short-run avoided cost methodologies that are conceptionally well understood, even though many difficult details needed to be worked out in compliance hearings.

The conceptual approach for development of the offer was not established for the long-run resource plan offer, and D.82-01-103 ordered utilities to make proposals for our review. After reviewing those offers, it became clear that evidentiary compliance hearings would lead to protracted conceptual cross-examination on how to pay small power producers entering long-term contracts for their value in deferring new utility capacity. Rather than starting with the utility proposals, we decided it would be preferable to define the alternatives, present some tentative proposals, and receive comments from parties. With this approach, parties' general positions could be better understood, and we hoped to establish a framework before going into detailed compliance hearings on specific utility offers filed within that framework.

So, we issued on November 18, 1982 a *Report and Request for Comments* (Report) which presented issues relating to Standard Offer No. 5 and tentatively proposed a framework for such an offer. The Report concluded that an interim offer should be based on a five-year forecast of utility projected short-run marginal costs, followed by prices in future years based on the energy and capacity costs of a new coal plant. The Report also proposed that payments escalate over the life of the contract to avoid complex termination requirements and that the small power producer

should be given flexibility about the output commitment it will take for future years. We asked parties to comment.

Responses by Parties to Commission Report

By January 31, 1983 the Commission received comments on the Report from 18 interested parties addressing both substantive and procedural issues. The comments were uniformly helpful. The comments included constructive criticisms of the Report and imaginative alternative frameworks for a long-run offer. The Commission was presented good informatioin on how to achieve a workable and useful long-term offer.

Most importantly, the comments indicated a broad consensus about the need to achieve the underlying purpose of the Standard Offer No. 5 which is to provide greater price certainty and to value the small power producers' facilities consistently with utility resources. Pacific Gas and Electric Company (PG&E), for example, while disagreeing with much in the Commission's Report, strongly endorsed the Report's purpose:

> "It has become apparent that the currently available standard offers do not meet the needs of all QFs. One of the major reasons for this is the high degree of future price uncertainty in these offers which adversely affects the ability of some projects to obtain financing.
>
> . . . A well designed standard offer, which mitigates the uncertainty, is consistent with avoided cost principles, and balances ratepayer and QF risk would also be desirable." (PG&E comments, page 1.)

PG&E offers a new proposal for a framework to provide greater pricing certainty for small power producers. Similarly, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) express general accord with the purposes of the Report and make new proposals for a standard offer framework.

Parties representing small power producers also agree that a greater pricing certainty is necessary. Many point out that differ-

ent facilities have different needs and possibly more than one long-term price offer should be available.

In addition to providing useful substantive information, the comments also suggest procedures for resolving this matter. There was significant difference of opinion among parties on procedure.

In our Report, we tentatively concluded "that resolution of conceptual and policy issues on what methodology is to be selected for the long-term offer does not require factual evidence, but can instead be more effectively decided through written comments and possibly oral presentations." (Commission Report, page 6.) We envisioned the conceptual and policy issues being resolved through a rulemaking-type procedure, while the details of an actual offer would be resolved in subsequent compliance hearings.

PG&E and SDG&E strongly disagree with this procedure. They argue that evidentiary hearings are necessary before the conceptual issues in the standard offer can be resolved. PG&E argues that fairness and due process require that hearings be held. "[I]t would be highly undesirable to resolve these very complex issues without the benefit of evidentiary hearings." SDG&E expresses similar concerns, arguing that the proposed format by the Commission would lead to lengthy compliance hearings and uncertainty about the details of any final order.

SCE also suggests that evidentiary hearings are necessary:

> "Edison believes that these hearings can be handled expeditiously, and without undue delay, if the scope of such hearings is clearly defined. While we certainly agree that the public interest is not served by delay, neither is it served by an incomplete examination of the complex issues surrounding this topic, possibly resulting in the selection of a costing methodology that inaccurately values QF power to utilities and their ratepayers. Edison suggests that, upon receipt and examination of the comments submitted by the various utilities and interested parties, the Commission should submit a 'summary report' which delineates both the various proposals presented and the issues to be examined in an evidentiary hearing."

Many of the other parties commented on procedure. Pacific Energy Resources (Pacific Energy) agreed to hearings. While stating that the Commission report provides a helpful framework, it argues that:

> "[I]ssues raised in this report can be only fully explored by means of hearings before the Commission. At such time each interested party and each utility can present alternative methods of implementing the proposals outlined by the Commission in its report and can present alternative proposals for consideration." (Comments of Pacific Energy, page 10.)

The hearings contemplated by Pacific Energy appear to involve direct presentations to the Commission rather than substantial cross-examination.

Occidental Geothermal, Inc. suggests that "further cooperative exchange of ideas is necessary before QFs can formulate any comprehensive proposal." (Comments of Occidental Geothermal, Inc., page 6.) To that end, it proposes a sequence of workshops, evidentiary hearings on issues relating to project risks, briefs, a decision to order utilities to file an offer, followed by compliance hearings and a decision. Ultrasystems Incorporated also suggests evidentiary hearings on risk-related issues.

California Manufacturers Association basically supports our proposed procedure. It suggests workshops, briefs, followed by a Commission decision, followed by compliance hearings on utility filings. California Independent Energy Producers also supports our proposal.

Natural Resources Defense Council agreed that evidentiary hearings are not necessary, but suggested parties should have the opportunity to comment on other parties' comments. Similarly, the California Energy Commission suggests another round of comments after this Commission issues a more detailed rule.

1. *Procedural Course and Guidelines*

The decision on how to proceed with these consolidated matters is important. We are aware that some QFs are anxious to see this standard offer resolved soon in order to decide whether to

begin projects. Delay on completing this offer could arrest QF development. On the other hand, it is also important to explore these issues to assure that ratepayers' interests are protected.

There are two major alternatives developed by parties. One proposed by utilities would be to hold evidentiary hearings on all of these issues, followed by an order, followed by compliance hearings on utilities' offers. The second general proposal would be the receipt of further written and oral comments, followed by compliance hearings.

Either approach would be overly time consuming and would not necessarily serve the interests of parties. The comments of parties convince us that a long-term standard offer is highly complex, involving avoided cost methodology, performance requirements, and termination penalties. The issues will not be quickly resolved under either procedure. Because of the complexity, we also are not certain that a Commission-ordered standard offer will best meet the needs of parties. It is evident that there are many possible standard offers which could be developed that are consistent with avoided cost pricing principles.

We have decided, therefore, to use a different procedure to resolve this matter before holding any formal evidentiary hearings. We have decided to hold a negotiating conference to give parties an opportunity to work together toward a methodology for an interim long-term standard offer[s]. We noted earlier that there is widespread consensus among parties on the immediate need for the long-term standard offer to provide greater pricing certainty and to reflect the value of QFs in deferring new utility resources. While there are many ideas on how to translate this concept into an offer, we think with the mutual objective of a timely decision in mind, parties can reach an accord.

The negotiating conference, to be held before any formal hearings on the long-term offers, is intended to achieve three things: (1) establish an offer[s] which can be filed by utilities at least on an interim basis which will be supported by the parties; (2) an agreement on a proposal clearly identifying issues, if any, which require further proceedings; and (3) a better understanding by all parties of each other's positions on this complex matter.

This, in turn, will lead to sharper definition of issues for any formal hearings in the future. The Commission, of course, will review and approve any interim offer, and address any proposals for additional proceedings. However, with substantial agreement among parties, we expect to be able to act more expeditiously.

The negotiating conference is a new procedure for the Commission. It should take place in a spirit of cooperation, not of adversarial posturing. Parties should come prepared for an intensive period of education, negotiation, and problem solving. Parties will all benefit by reaching an accord because an interim offer may then be quickly put in place.

We expect the negotiating conference to reach substantial agreement within one month after it commences in the middle of May. We will make as much time available during that month as is necessary for parties to work out an agreement. A tentative schedule for the conference will be presented by the administrative law judge (ALJ) on the first day of the conference. Parties will have an opportunity to review and discuss it. We expect the schedule to permit a thorough presentation of positions on the major issues by parties, followed by analysis, followed by negotiations to settle on an offer. The dynamics of the conference will, of course, depend upon the nature of the issues that need to be discussed.

The negotiating conference will begin on May 23, 1983, and will last not longer than four weeks, with regularly scheduled meetings. Parties should send representatives who can commit extensive time to this process and who can present positions and negotiate. We encourage QFs with similar interests to join and work together. We also encourage parties not only to send technical staff, but also be represented by those who can negotiate and make decisions. The staff will be represented by the Director of the Utilities Division, who will be supported by technical staff and staff counsel.

When the negotiating conference ends, the ALJ will issue a ruling which sets the time in which the three applicant utilities shall amend their applications with new standard offers. After a reasonable time for all parties to review and evaluate the amended

standard offers, we will schedule a prehearing conference to evaluate the need for evidentiary hearings and, if they are required, their scope.

In order to encourage open participation at the negotiating conference, we will order that Rule 50 of our Rules of Practice and Procedure shall apply.[1] That will encourage a free and candid exchange of information, ideas, and alternatives.

2. *Issues for Resolution*

The comments in response to our Report provided many useful suggestions on defining a long-term contract and highlighted the issues that need to be settled. Two broad issues arise. First, what costs are avoided by long-term QF contracts? Second, a related and workable pricing mechanism, with appropriate contract terms and conditions, must be established to pay the QFs for their contribution of providing electricity to avoid those costs. The nature of these payments may vary depending upon the conditions of operation agreed upon by QFs. Generally, the utilities devoted more attention to the first issue of costing, while QFs generally devoted more to the latter issue of pricing.

a. *Costing Methodologies*

The utilities generally support use of projected short-run avoided costs (i.e., marginal running costs plus shortage value) for use in defining a long-run offer. Utilities assert that the criteria for determining whether a utility would add a new resource depends on whether the capital and operating costs of the proposed resource is less than the projected short-run avoided cost. Resources are added until the two are equal according to the rule of economic dispatch.

We agree that methodologies using projected short-run avoided costs and using the costs of new resources should produce the

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[1] Rule 50 provides as follows: "(Rule 50) Facts Disclosed Privileged. Facts disclosed in prehearing conferences are privileged. Except by agreement, they shall not be used against participating parties, before the Commission or elsewhere, unless proved by evidence other than that employed in disclosing such facts."

same results in theory. However, the problem is translating projected costs into QF prices. The utilities contend that the short-run methodology can be used. The Commission's Report found that a coal plant would be a simpler proxy. Other parties expressed mixed views on the issue.

We expect this issue to be developed fully in the negotiating conference. Parties should have the opportunity to demonstrate clearly how to derive avoided cost numbers from their marginal cost methodology. A major criteria for consideration will be workability as well as theoretical validity. We are looking for *results*. We expect the negotiating conference to develop a consensus methodology that fairly reflects the long-term value of QF power that can be readily implemented through pricing.

b. *Pricing*

It is apparent from the comments that developing an avoided cost estimate represents only part of the problem of developing a standard offer. Equally difficult is translating those costs into a contract with prices, terms, and conditions.

QFs have different views on what the contracts should be like. Some QF representatives, particularly those with cogeneration facilities, are interested in fixing incremental heat rates in a contract, but not fixing total fuel prices, since a cogenerator's fuel price may fluctuate with the rates of serving gas utilities. Others would like more pricing certainty, including in some cases, levelized payments. Another area of difference involves performance requirements. Some QFs can produce reliably based on very stringent performance standards, others produce intermittently and seek a more flexible standard.

These differences explain why QFs want an array of standard offers; however, we must caution the parties that trying to devise a number of standard offers to accommodate all QF situations—and which do not result in favoring some QF technologies over others—will result in tremendous complexity and, of course, attendant delay.

We welcome some variety of long-term offer options, but we stress that all variations must be consistent with avoided cost

principles. If levelized payments are proposed, for all or part of the contract term, we expect corresponding proposals to mitigate potential loss to the ratepayer resulting form nonperformance or overpayment.

c. *Resolution of Issues Resulting From the Negotiating Conference*

We expect that most of the issues can be resolved in the negotiating conference to permit an agreement on an offer that utilities should file on an interim basis. The agreement should include both a conceptual framework and a means of deriving specific prices. We do not expect that parties will waive their rights to further proceedings in this matter. The long-term offer methodology is evolving, and it may be useful to further analyze the question later. Therefore, in addition to a standard long-term offer, we solicit a consensus from parties on a procedure for further analysis of the long-term offers.

All parties should come to the negotiating conference with the list of issues which they see needing to be resolved, and should be prepared with proposals for resolution of issues. Staff will prepare and submit a comprehensive listing based on the comments for review already filed by parties. We expect the proposals to be offered with a spirit of compromise. Everyone will have the opportunity to present their proposals at the negotiating conference and make suggestions for improvements of other proposals.

INTERIM ORDER

IT IS ORDERED that:

1. A negotiating conference to be presided over by ALJ Alderson shall be held on May 23, 1983, at 9:30 a.m. at Hastings College of the Law, 198 McAllister Street, Room K, San Francisco. This conference shall continue over a four-week period, with the schedule to be set by the ALJ. It will not be reported by the Commission's Reporter, and the use of material disclosed during the conference will be governed by Rule 50 of the Commission's Rules of Practice and Procedure.

2. After the negotiating conference ends, the ALJ shall issue a ruling providing a time limit within which the applicants shall amend their applications with revised standard offers. Thereafter, a prehearing conference shall be scheduled to assess the need for hearings and define their scope.

3. This order shall also be served on the applicants and the parties served with D.82-12-120 in Application 82-03-26 et al.

This order is effective today.

Dated May 4, 1983, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

I abstain.
/s/ PRISCILLA C. GREW
Commissioner

Supreme Court, U.S.
FILED
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CLERK

No. 87-178

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation,
Petitioner,

vs.

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA,
Respondent.

REPLY TO RESPONDENT'S BRIEFS IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

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I
INTRODUCTION

Pacific Gas and Electric Company ("PGandE") respectfully submits this reply to the briefs in opposition to its petition for writ of certiorari which were filed by the California Public Utilities Commission ("CPUC"), Ultrapower, Inc., GWF Power Systems Company, Basic American Foods, Inc., and the Independent Energy Producers Association ("IEP").

Respondents recite a variety of reasons for denying certiorari. First, the CPUC alone claims PGandE's appeal is untimely because it should have been filed in 1983. Second, respondents argue the FERC rules shelter the challenged prices. Third, respondents claim that the document in dispute—"Interim Standard Offer No. 4" ("interim SO 4")—*sub silentio* provided price certainty even after its fixed price schedules terminated. Fourth, respondents contend that the CPUC's decisions are based on

findings of fact and hence are unreviewable. Fifth, respondents assert that PGandE had a duty to extend unilaterally the interim SO 4 fixed price schedules beyond those approved by the CPUC in 1983. In addition, Ultrapower and GWF contend the CPUC had some independent authority under state law to compel PGandE to pay prices that exceed the federal maximum. These contentions have no merit.

II
PGandE'S APPEAL WAS TIMELY

The CPUC alone asserts PGandE's petition is untimely because PGandE should have appealed the CPUC's original 1983 decision authorizing interim SO 4, rather than contested the CPUC's 1986 decisions that "interpreted" interim SO 4. Since the very issue here is whether or not interim SO 4 contained fixed prices for the time periods now claimed, this argument is really a substantive one masquerading in procedural dress.

PGandE does not challenge the prices that the CPUC approved in 1983, which consisted of fixed prices for firm capacity deliveries beginning by the end of 1987, and fixed prices for energy and as-delivered capacity delivered through 1997. Although even these fixed prices have turned out to greatly exceed the Public Utility Regulatory Act's ("PURPA") maximum of "avoided cost," PGandE has complied with the CPUC's 1983 decision. But PGandE does dispute whether the CPUC's 1983 decision secretly incorporated forecasted prices beyond the 1987 firm capacity prices and the 1997 energy and as-delivered capacity prices. Not until 1986, in the three decisions which PGandE timely appealed, did the CPUC order PGandE to "supplement" the fixed price schedules it had approved in 1983. Since PGandE indisputably sought timely review of those 1986 decisions, the CPUC's current contention that PGandE's petition for writ of certiorari is time-barred is meritless.[1]

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[1] *See, e.g., Chenango and Unadilla Tel. Corp. v. Pub. Serv. Comm'n* 46 A.D.2d 601, 364 N.Y.S.2d 578, 580 (N.Y. Sup. 1975) (petitioners had no complaint concerning Commission's prior order until it issued an order "clarifying" its prior order to their detriment).

III
FERC RULES DO NOT SHELTER THE EXTENDED PRICES

Respondents, in general, claim that the new additional three years of fixed prices mandated by the CPUC in 1986 do not violate PURPA because they were agreed upon and approved in 1983, and thus are sheltered by 18 C.F.R. § 292.304(b)(5) (1987), which states that fixed rates in long-term contracts do not violate FERC rules if the fixed rates differ from actual avoided cost at the time of delivery. PGandE does not argue that the new prices violate PURPA solely because they in fact exceed avoided cost. They offend PURPA because firm capacity prices for 1988-1990 and energy and as-delivered capacity prices for 1998-2000 were *not* negotiated in 1983 and the Commission at no point in time has determined that they represent a reasonable estimate of avoided cost.

IV
NEITHER THE LANGUAGE OF INTERIM SO 4 NOR THE HISTORY OF ITS ADOPTION PROVIDES ANY PROOF OF AN AGREEMENT TO PAY FIXED PRICES BEYOND THOSE SET FORTH IN THE INTERIM SO 4 PRICE SCHEDULES

The interim SO 4 fixed energy prices are based on a fifteen-year forecast approved in 1983. Based on the interim SO 4 requirement that energy deliveries begin within five years of execution, respondents in essence assert that the fifteen-year forecast agreed upon in 1983 was intended to roll forward automatically with interim SO 4's prolonged availability. But adding three years to the 1983 forecast without updating the forecast's assumptions simply converts it into an 18-year forecast. No such intent appears anywhere in interim SO 4 or in the CPUC's decisions.

Respondents' claim also implies that had the CPUC suspended interim SO 4 in 1984, the price forecast would have ended in 1989. Similarly, if the CPUC had not suspended interim SO 4

until 1986, the price forecast would extend to 2001. Yet nothing in interim SO 4 or in the CPUC's 1983 decision approving interim SO 4 suggests that the parties agreed to an indefinite forecast which was to recede or stretch with interim SO 4's availability. To the contrary, the dates employed could hardly have been more specific. Even in Decision No. 86-12-013, slip op. (Cal.P.U.C. Dec. 3, 1986), the Commission acknowledged that "QFs are not inherently *entitled* to indefinite capacity price extension." (Pet. App., p. A-143 n. 2) (emphasis in original)

Interim SO 4 belies unlimited price certainty. Instead, in Article 2 it warns that energy and capacity prices "have wholly *or partly* been fixed at the time of execution." (Pet. App., p. A-187) (emphasis added) The same Article commits the parties only to "the prices fixed in this Agreement," and requires the seller to waive rights to relief only from the "prices set forth in Appendices B, D and E." *Id.*

As respondents note, on October 4, 1985, PGandE petitioned to extend for three more years the firm capacity price schedule approved in PGandE's 1984 test year general rate case decision, Decision No. 83-12-068, slip op., (Cal.P.U.C. 1983), for another standard offer, Standard Offer No. 2 ("SO 2"). Respondents now assert that PGandE's 1985 request to extend the firm capacity price table in SO 2 conclusively proves that the firm capacity price table in interim SO 4 should be extended. The purpose of the SO 2 petition and the lack of any similar petition for interim SO 4 prove quite the contrary.

PGandE petitioned to revise the SO 2 price schedule, which ended in 1988, for QFs who executed SO 2 before the issuance of PGandE's next general rate case decision, when PGandE anticipated a new schedule would be approved. The petition was necessary because CPUC Resolution ALJ-151, issued June 6, 1984, had postponed PGandE's next general rate case for one year. The petition was intended to fill the price gap that the change in the rate case schedule had created. However, before the CPUC acted on PGandE's petition, it suspended SO 2 because the "current capacity price schedules would create a significant potential for overpayment." Dec. No. 86-05-024, slip op. at 27

(Cal.P.U.C., May 7, 1986). PGandE accordingly requested that its petition be withdrawn.

The history of PGandE's petition to extend the SO 2 price schedule is pertinent, but not for the reasons that respondents suggest. First, the filing of the petition demonstrates that PGandE did not take it upon itself to change a standard offer's prices unilaterally, but instead sought prior CPUC approval. Second, had the new extended prices somehow been implicit in the price schedule, no petition whatever would have been required. Third, unlike interim SO 4, SO 2 was based on a methodology developed in evidentiary hearings, and stemming from those hearings, a rationale did exist for extending the price table. Fourth, unlike interim SO 4, SO 2 had no Article 2 committing the parties to "the prices fixed in this Agreement." Finally, as the CPUC stated in 1984 when it refused to amend a price term at respondent IEP's request, interim SO 4 was a "negotiated package," and "a change in one term would require reexamination of all other terms of the standard offer." (Pet. App., p. A-58)

V

THE CPUC'S INTERPRETATION OF INTERIM SO 4 RESTED UPON A CONCLUSION OF LAW

As the CPUC told the California Supreme Court in its answer to PGandE's petition for writ of review, the CPUC's 1986 decisions were based on its interpretation of interim SO 4's "purposes and the intent of the parties, *as manifested in the Commission decisions that originally approved the agreement and directed its development.*" (CPUC Answer, pp. 2-3) (emphasis added) The CPUC never held hearings or heard evidence concerning interim SO 4's meaning or the parties' intent.

The CPUC had the option of holding a hearing on the various petitions for modification to extend the interim SO 4 price tables. *See* Cal. Admin. Code tit. XX, R. 8.1, 8.2. But no party requested evidentiary hearings and the CPUC chose not to conduct any. Only legal briefs, which under Cal. Pub. Util. Code § 1710 and Cal. Admin. Code tit. XX, R. 14.5 cannot be treated as evidence, were submitted. Moreover, as the California Supreme Court

stated in *Boreta Enterprises, Inc. v. Department of Alcoholic Beverage Control,* 2 Cal. 3d 85, 104 (1970), quoting *English v. City of Long Beach,* 35 Cal. 2d 155, 158 (1950):

> In California, administrative tribunals which are required to make a determination after a hearing cannot act upon their own information and nothing can be considered as evidence that was not introduced at a hearing of which the parties had notice or at which they were present.

In the absence of extrinsic evidence, the interpretation of written documents presents questions of law, not questions of fact. Contrary to respondents' assertions, mere denomination of the CPUC's interpretation as findings of fact does not transform its interpretation from a legal to a factual conclusion. Thus, the CPUC's decisions rested exclusively on conclusions of law, which do not merit the special deference owed administrative fact-finding.

VI

PGandE COMPLIED FULLY WITH THE COMMISSION DECISIONS AUTHORIZING INTERIM SO 4 IN DRAFTING AND INTERPRETING INTERIM SO 4

Respondents assert that the CPUC's 1983 decision authorizing interim SO 4 required PGandE unilaterally to add three additional years of fixed prices to the original interim SO 4 fixed price tables. Some claim that PGandE did not properly implement Decision No. 83-09-054 (Pet. App., p. A-2) when it initially prepared interim SO 4. Others assert that PGandE violated Decision No. 83-09-054 by not independently updating and extending the interim SO 4 price schedules. Both contentions are wrong, because the three price schedules at issue are identical to the price schedules that PGandE submitted to the CPUC in 1983, and identical to the price schedules that the CPUC approved without change in Decision No. 83-09-054. The schedules contained firm capacity prices only through 1987, and fixed energy and as-delivered capacity prices only through 1997. Since these schedules were computed prior to the 1983 decision, and the decision did not order any modifications to them but instead

approved them, the schedules fully complied with Decision No. 83-09-054.

Decision No. 83-09-054 also did not obligate PGandE to update or extend the interim SO 4 price schedules that it approved. In Decision No. 83-09-054, CPUC stated that revisions to the 15-year forecast embodied in the fixed price schedules "can be addressed in the subsequent hearings." Thus, the mechanism for any revisions was to be CPUC hearings and orders based on those hearings, not unilateral utility action. PGandE could not have changed interim SO 4 without a CPUC order. Making unilateral changes in the terms of interim SO 4 would have placed PGandE in violation of CPUC orders barring a utility from altering any of the terms of a standard offer except upon order by the CPUC or at the specific request of QF for nonstandard, negotiated terms. *See, e.g.,* Dec. No. 85-06-163, slip op. at 24-26 (Cal.P.U.C., June 21, 1985). In two later decisions issued before interim SO 4 was suspended, the CPUC specifically refused to alter the price provisions of interim SO 4 in any way whatsoever. *See* Dec. No. 83-12-050, slip op. (Cal.P.U.C., Dec. 20, 1983) (Pet. App., p. A-50); Dec. No. 84-08-035, slip. op. (Cal.P.U.C., Aug. 1, 1984) (Pet. App., p. A-56). PGandE had no duty to extend on its own volition the price schedules that the CPUC had approved in 1983.

VII
THE CPUC DID NOT EXERCISE INDEPENDENT STATE AUTHORITY IN ORDERING THE PRICE EXTENSION

Ultrapower and GWF contend at length that the CPUC had independent authority under state law to order PGandE to pay QFs prices that exceed avoided cost.[2] But, as the CPUC (p. 3),

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[2] Contrary to GWF and Ultrapower's contentions, PGandE does not and has not conceded that *Consolidated Edison Co. v. Public Serv. Com'n,* 63 N.Y. 2d 424, *appeal dismissed,* 470 U.S. 1075 (1985) was correctly decided. PGandE only noted that the validity of that decision need not be reached, because the CPUC did not invoke independent state authority to justify either interim SO 4 or its extension of the interim SO 4 fixed price schedules.

Basic (p. 12, n. 11) and IEP (p. 10) concede, the CPUC has never invoked any independent state authority to support its decisions. Consequently, Ultrapower and GWF's argument is mere digression.

VIII
CONCLUSION

For these reasons, the Court should issue a Writ of Certiorari to review the judgment and opinion below.

Respectfully submitted,

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